sheer age of the prior study, FG&E concluded that a new study ("G/E Split Study") was required to ensure the validity of the allocation methodology. Exh. FGE-MHC-1 (Electric) at 053; Exh. FGE-MHC - 6 (Electric); Exh. FGE-MHC-1 (Gas) at 056; Exh. FGE-MHC - 6 (Gas).

The G/E Split Study results were very similar to the results of the 1978 Study and recommended that, on an overall basis, 35.75% of the common costs should have been allocated to the Gas Division and 64.25% should have been allocated to the Electric Division. Exh. FGE-MHC-1 (Gas) at 056; Exh. FGE-MHC-6 (Gas); Exh. FGE-MHC-1 (Electric) at 054; Exh. FGE-MHC-6 (Electric); Exh. DTE-6-12. By comparison, the 1978 Study, used to allocate the test year common costs, resulted in 35.97% of the common costs being assigned to the Gas Division and 64.03% assigned to the Electric Division. Exh. FGE-MHC-1 (Electric) at 054; Exh. FGE-MHC-1 (Gas) at 056; Exh. DTE-6-12.

The adjustment for Gas/Electric Allocations reflects the allocation methods for common Gas/Electric expenses as recommended in the G/E Split Study. Exh. FGE-MHC-1 (Electric) at 055; Sch. MHC -7-10 (Electric). See also Exh. FGE-MHC-1 (Gas) at 057; Sch. MHC-7-14 (Gas); Exh. DTE-1-11; Exh. DTE-3-8; Exh. DTE-3-10; Exh. DTE-6-21. This adjustment relates to both O&M Expense and Taxes Other Than Income.

m. Inflation (Common)

FG&E requests an inflation allowance to be added to the test year Electric Division revenue requirement of $127,171. DTE-RR-6, updated 10/02/02; Exh. FGE-MHC-1 (Electric) at Sch. MHC-7-12 (Electric). In addition, FG&E requests an inflation allowance to be added to the test year Gas Division revenue requirement of $71,591. DTE-RR-6, updated 10/02/02; Exh. FGE-MHC-1 (Gas) at Sch. MHC–7-15 (Gas).

The Department permits utilities to increase their test year residual O&M by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year.[27][28] Berkshire Gas Co., D.T.E. 01-56 at 72; Massachusetts Elec. Co., D.P.U. 95-40 at 64; Cambridge Elec. Light Co.; D.P.U. 92-250 at 97 (1993); Massachusetts Elec. Co.; D.P.U. 92-78 at 60 (1992). In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures for those cost categories for which FG&E has proposed pro forma adjustments. Berkshire Gas Co., D.T.E. 01-56 at 71-72 (2002); Boston Gas Co., D.P.U. 96-50 (Phase I) at 113.

FG&E has demonstrated its efforts to control costs. For instance, FG&E documented its efforts to control payroll costs with the survey and benchmarking activities. Tr. 8/23/2002 (Vol. 11) at 1351-1352; Exh. FGE-DTE-4-5 (Common); AG-RR-7; Exh. AG-5-12 (Gas); Tr. 8/23/2002 (Vol. 11) at 1363; Exh. AG-5-13 (Gas, Electric, Common); Exh. FGE-Surveys; Exh. AG-5-15 (Gas). O&M Payroll for the Electric Division has decreased from 1996 to test year 2001. DTE RR-6 (Electric) updated 10/02/02, at Sch. MHC-7-12 (Electric), at 4. For the same five year period, O&M Payroll for the Gas Division has increased by only 2%. DTE RR-6 (Gas) updated 10/02/02 at Sch MHC -7-15 (Gas), at 4.

Further, O&M Employee Fringe Benefits over this same period have decreased dramatically, as has O&M Property and Liability Insurance. Id. In addition, FG&E has demonstrated its efforts to control health care costs, as evidenced by, among other things, the detailed description of the methods that FG&E is using and has used in the recent past to reduce its health care costs. Exh. AG-1-52 (Common). As a result, the average health care cost per

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27 Residual O&M are those categories of O&M expense for which no specific pro forma expense adjustments have been proposed by FG&E and which are impacted by general inflation.

28 The inflation allowance will be updated to reflect the most recent GDPIPD data at the time of the filing of the Company's Reply Brief on October 24, 2002. Exh. FGE-MHC-1 (Electric) at 061.

employee fell from 2000 to the test year 2001. Exh. AG-1-51 (Common). Total medical and dental insurance costs decreased from 1992 to the test year 2001. Exh. DTE 1-30 (Gas, Electric, Common). Finally, in the last rate reviews for both the Electric Division and the Gas Division, the Department found that FG&E had shown it was effectively containing costs and allowed inflation adjustments in each case. D. T. E. 99-118 at 44 (2001); D.T.E. 98-51 at 101 (1998).

Consistent with Department precedent, FG&E applied an inflation allowance to test year residual O&M Expenses for the Electric Division and the Gas Division. DTE-RR-6, updated 10/02/02; Exh. MHC-1 (Electric) at Sch. MHC-7-12 (Electric); Exh. MHC-1 (Gas) at Sch. MHC – 7-15 (Gas). The inflation allowance has been calculated based on the projected inflation rate of 2.54% from the midpoint of the test year to the midpoint of the rate year. Exh. FGE-MHC-1 (Electric) at Sch. MHC –7-12 (Electric); see also Exh. FGE-MHC-1 (Gas) at Sch. MHC-7-15 (Gas).

In order to determine the level of test year residual O&M Expense, the test year O&M Expense was reduced by (1) purchased gas costs, (2) expenses that have been adjusted separately and (3) expenses that are not impacted by general inflation. Exh. FGE-MHC-1 (Electric) at Sch. MHC –7-12 (Electric); Exh. FGE-MHC-1 (Gas) at Sch. MHC–7-15 (Gas). The inflation rate was separately calculated, as measured by the projected growth in the Gross Domestic Product Implicit Price Deflator (GDPIPD) from the midpoint of the test year to the midpoint of the rate year. Exh. FGE-MHC-1 (Electric) at Sch. MHC –7-12 (Electric); Exh. FGE-MHC-1 (Gas) at Sch. MHC –7-15 (Gas).

n. <u>Rate Case Expense (Common)</u>

FG&E seeks an increase of $107,393 for the Electric Division. DTE RR-6 (Electric), updated 10/02/02 at Sch. MHC-7-13 (Electric). FG&E seeks an increase test year rate case expense of $70,821 for the Gas Division. Exh. DTE-2-15; DTE RR-6 (Gas), updated 10/02/02 at

Sch. MHC–7-16 (Gas). The adjustment was calculated based upon the Department precedent for determining the appropriate normalization period and the average length of periods between the filing dates of FG&E's last four rate case filings was used to derive the annual level of rate case expense to be included in rates for this proceeding. Id.; D.T.E. 98-51 at 54.

The Department allows recovery for rate case expenses if the expenses are known and measurable. Berkshire Gas Co., D.T.E. 01-56 at 75. A known and measurable expense is a quantified expense that has been incurred by FG&E. Id.; D.T.E. 98-51 at 62. The Department has directed companies to provide all invoices for outside services that document the number of hours billed, the billing rate, and the nature of the services provided. D.T.E. 98-51 at 61; Boston Gas Co., D.P.U. 96-50 (Phase I) at 79. The Department has also expressed a concern for the accuracy of rate case estimates and the need for timely updates of the estimates. D.T.E. 98-51 at 56-57.

The Department has directed that outside legal and consulting services must be subject to a competitive bidding process, or an adequate justification must be provided for the failure to issue a request for proposal ("RFP"). D.T.E. 98-51, at 59-60; Boston Gas Co., D.P.U. 96-50 (Phase I) at 79. In order to derive an annual rate case expense, a normalization period must be developed and a representative rate case amount must be established. The Department's standard treatment for determining the appropriate normalization period is to average the length of periods between the filing dates of a company's last four rate case filings, including the instant case, rounded to the nearest whole number. D.T.E. 99-118 at 40. In Berkshire Gas, the Department initially normalized rate case expenses so that a representative annual amount could be included in the cost of service, however, the Department normalized the expenses over the term of Berkshire's proposed and approved PBR plan, or 10 years. Berkshire Gas Co., D.T.E. 01-56, at

77. FG&E's rate case expense as proposed is reasonable, appropriate and established in a manner that is consistent with Department precedent.

FG&E contracted with various non-affiliated consultants for outside services with regard to the Depreciation Study, developing a PBR Plan, determining a reasonable market Cost of Common Equity, performing Cost of Service Studies and reviewing and reestablishing the appropriate Allocation of Common Costs between FG&E's Gas and Electric Divisions, and for acquiring Legal Services. Exh. FGE MHC-1 (Gas) at 061; see also Exh. FGE-MHC-1 (Electric) at 062-063.

i. Rate Case Expense - Competitive Bids

With regard to the Depreciation Study presented by FG&E, FG&E employed a competitive bidding process in order to select the consultant, James H. Aikman. Exh. FGE-MHC-1 (Gas) at 061; see also Exh. FGE-MHC-1 (Electric) at 063. In addition, with regard to FG&E's PBR, filed April 16, 2002, FG&E competitively bid, and selected from that competitive process, the services of Russell Feingold and Navigant Consulting. Exh. AG-5-17 (Common).

ii. Rate Case Expense - Other Providers

Each of the other consultants for the rate proceedings were selected based on reasonable and legitimate qualitative and quantitative (price) criteria, other than a competitive bidding process. FG&E reviewed the services required in order to bring together all the components of the rate request and decided that additional criteria weighted more heavily than the benefits of relying solely upon competitive bidding, both to FG&E and to customers. Exh. FGE-MHC-1 (Gas) at 062; see also Exh. FGE-MHC-1 (Electric) at 063.

FG&E did not competitively bid the outside consulting services to develop its position for Cost of Capital and its Cost of Service studies. Exh. FGE-MHC-1 (Gas) at 062; see also Exh. FGE-MHC-1 (Electric) at 064. FG&E has developed, over many years, working relationships with Management Applications Consulting and with FINANCO, and similar qualitative and quantitative criteria apply here. Exh. FGE-MHC-1 (Gas) at 062-063; Exh. FGE-MHC-1 (Electric) at 064. These consultants have familiarity with FG&E, especially as it pertains to rate case issues, and such knowledge reduces costs that otherwise would be incurred in learning and understanding the combined and separate operations of the Electric and Gas Divisions. Exh. Exh. FGE-MHC-1 (Electric) at 064; see also FGE-MHC-1 (Gas) at 062. Equally important in this decision is the fact that these consultants had performed similar studies in prior rate proceedings and already possessed much of the historical data needed to perform such studies, thus reducing lead and clock time. Exh. FGE-MHC-1 (Electric) at 064; see also Exh. FGE-MHC-1 (Gas) at 062. Having this information on hand permitted them to produce the studies more efficiently and at less cost than consultants unfamiliar with FG&E. Exh. FGE-MHC-1 (Electric) at 064; see also Exh. FGE MHC-1 (Gas) at 062; Tr. 8/23/2002 (Vol. 11) at 1336.

The Attorney General has focused his criticism on Legal Expenses only with regard to the three providers for whom FG&E justified its decision not to seek a competitive bid. No party, therefore, contests the fact that FG&E chose not to competitively bid the services of MAC or FINANCO.

With respect to Legal Services, FG&E did not competitively bid these services due to additional price and non-price criteria that is adequate, reasonable and effective toward containing costs; such qualitative factors as a long-standing relationship with the law firm, an existing depth of understanding regarding the complexities of FG&E's corporate structure, its combined utility status, and its multi-jurisdictional regulatory framework. Tr. 8/23/2002 (Vol. 11) at 1328-1329. In addition, Mr. Collin testified a second criteria applied:

> The other one, of course, is a quantitative one; and we have a responsibility to ensure that the services we acquire are competitive and are cost-effective. And again, my assessment and our assessment is, given our billing arrangement with the law firm of LeBoeuf, Lamb, and the fact that they have offered us a discount to their standard billing rates, coupled with my general knowledge of the legal costs in matters where we have not used LeBoeuf -- we don't use them in every instance for every type of specialty -- has given us comfort that we are in a reasonable competitive range relative to what we might spend for other firms.

Tr. 8/23/2002 (Vol. 11) at 1328-1329.

In spite of the Attorney General's complaints, the Department has found these criteria valid and has determined that FG&E adequately justified its decision not to seek competitive bids because of LeBoeuf, Lamb's institutional knowledge of Unitil, FG&E, FG&E's affiliates and FG&E's unique combined gas and electric operations. Berkshire Gas Co., D.T.E. 01-56, at 76, Fitchburg Gas and Elec. Light Co., D.T.E. 98-51 at 60. Such understanding and background creates efficiencies in the regulatory process, reduces unnecessary confusion, and better serves both FG&E and its ratepayers.

During the course of the hearings, Mr. Collin further substantiated FG&E's cost containment efforts for rate case legal services by discussing a written discount received from LeBoeuf for work relating to the rate cases. See Tr. 8/23/2002 (Vol. 11) at 1326 (mistakenly identified discount as hourly). This discount is in the record and is a clear statement of FG&E's continuing bill scrutiny of even its longest-term legal counsel and a testament to the success of its cost containment efforts. AG-RR-44 (Common) Confidential. Furthermore, mindful of the Department's requirements, throughout the proceeding, with exception of the first two days, the hearings were attended by just a single LeBoeuf, Lamb attorney at a time, and extensive use was made of highly-experienced non-attorneys to handle discovery. See Exh. DTE-2-15 (10/4/02); Tr. 8/23/02 (Vol. 11) at 1334-1335; Exh. DTE 2-15. Finally, it should be noted that the same outside experts assisting with the Unitil rate and restructuring case in New Hampshire are working on this case, thus allowing FG&E to realize all of the associated synergies. Exh. AG-5-01 (Gas).

Similarly, FG&E placed significant effort in developing and updating the rate case expense estimate for this proceeding. The original expense estimates were prepared after discussions with the various functional managers responsible for the preparation of the rate request. Exh. FGE MHC - 1 (Gas) at 064; Exh. FGE-MHC-1 at Sch MHC-7-16 (Gas); see also Exh. FGE MHC-1 (Electric) at 065; Exh. FGE-MHC-1 at Sch. MHC-7-13 (Electric). These managers also had budget responsibility for internal expenditures and had detailed conversations with the consultants themselves in order to estimate reliably the expected Rate Case expense. Exh. FGE MHC-1 (Gas) at 064; see also Exh. FGE-MHC-1 (Electric) at 065.

FG&E has continued to update its rate case expense on regular intervals. Updates of actual and estimated expenditures for the Electric Division and Gas Division, along with detailed supporting invoices from the outside consultants for actual costs reflected in the updates, were provided at two week intervals during the proceeding as FG&E monitored these expenditures. Exh. DTE 2-15 (Common, 6 supplemental responses). These updates complied with Department directives regarding the filing of detailed invoices for outside services for the cases and assisted FG&E in its continual monitoring of actual costs against estimates for the rate cases on a timely basis. On September 20, 2002, FG&E updated the rate case estimates on a timely basis for the Electric Division and Gas Division based upon the work associated with the unanticipated large volume of data requests associated with the rate case. Exh. DTE-2-15 (Common) Supplemental Response-9/20/02.

FG&E has presented substantial evidence demonstrating that it has managed the rate cases effectively, particularly in view of the complexity of the simultaneous gas and electric cases and the volume of data requests received, and that rate case expense is reasonable, well documented and that an appropriate level of such expense should be included in rates.

The pro forma adjustment to reflect the estimated level of rate case expense for both the Electric Division and the Gas Division has been calculated based upon established Department precedent and increases test year rate case expense by $107,393 for the Electric Division. Exh. DTE-2-15 (9/20/02); DTE RR-6 (Electric) updated 10/02/02 at Sch. MHC-7-13 (Electric); see also DTE RR-6 (Gas) updated 10/02/02 at Sch. MHC–7-16 (Gas), line 11 (test year rate case expense increased $70,821 for Gas Division). The adjustment was calculated based upon the Department precedent for determining the appropriate normalization period and the average length of periods between the filing dates of FG&E's last four rate case filings was used to derive the annual level of rate case expense to be included in rates for this proceeding. Id.; Fitchburg Gas and Elec. Light Co., D.T.E. 98-51 at 54; see also Fitchburg Gas and Elec. Light Co., D.T.E. 99-118 at 40.

o. Rental Programs

As discussed supra at Section VII.B.2, the Department no longer permits utilities to include the costs of providing a rental program in its above-the-line revenue requirement for setting rates. Accordingly, FG&E proposed an adjustment to remove the O&M expenses related to the electric water heater rental program in the amount of $15,163 from the Electric Division revenue requirement. Exh. FGE-MHC-1 at Sch. MHC-7-14 (Electric). Likewise, FG&E proposed an adjustment to remove the O&M expenses for the water heater and conversion burner rental program from the Gas Division revenue requirement in the amount of $58,739. Exh. FGE-MHC-1 at Sch. 7-17 (Gas).

The Department directed FG&E to provide a separate water heater allocation for Accounts 901, 903, 904, 905, 907 to 910, 920 to 922, 924 to 926, 928, 930 and 935 because these accounts contain costs that are incurred for both utility and non-utility customers. D.T.E. 98-51 at 67. Because this requirement was established due to the non-utility character of these services, and was not restricted to gas operations, FG&E applied the precedent to its Electric Division revenue requirement also. In order to ascertain the appropriate allocations, FG&E performed an allocation study for both its Electric Division and Gas Division to determine allocable expenses attributable to Rental Program, or non-utility, operations. Exh. FGE-MHC-7 (Electric); Exh. FGE-MHC-7 (Gas).

From an administrative standpoint, the Rental Programs for both Electric and Gas operations function like that of Massachusetts Electric Company (MECo), in that FG&E contracts with outside vendors to maintain the inventory of water heater tanks, to service the tanks, and to install replacements. Id. FG&E's Customer Service handles inquiries for the program, signs leases, maintains a customer list and refers and supervises the outside vendors. Id. Because of the similarities and for administrative ease, FG&E adopted MECo's allocation method. See, Massachusetts Elec. Co., D.P.U. 89-194/95 at 49.

In order to allocate non-utility O&M, MECo uses a revenue allocator, with the exception of Account 904 (Uncollectible Expense), which is a direct charge. Exh. FGE-MHC-1 (Electric) at 068; Exh. FGE-MHC-1 (Gas) at 067. However, at the time of preparing the study (February 1, 2002), there was no precedent of the allocation of costs for Account 924, Property Insurance, so FG&E used gross plant to allocate Property Insurance amounts attributable to rental operations from the its utility operations. Exh. FGE-MHC-1 (Electric) at 067; Exh. FGE-MHC-1 (Gas) at 068-069. The adjustment performed had two purposes: first, it removes the test year direct O&M expenses charged to the Rental Program in the amount of $13,866 for the Electric Division, and $34,244 for the Gas Division. Exh. FGE-MHC-1 at Sch. MHC-7-14 (Electric); Exh. FGE-MHC-1 at Sch. MHC-7-17 (Gas). Second, it removed allocated costs on a pro forma basis in the amount of $1,297 for the Electric Division, and $24,495 for the Gas Division. Id.

i. Response to Attorney General

The Attorney General does not dispute the manner of any of FG&E's proposed allocations for the expenses related to the Rental Program. However, he argues that five additional pro forma adjustments are necessary, claiming FG&E failed to allocate "any" of the following: (1) property and liability insurance expense; (2) medical and dental expense; (3) PBOP and retiree trust fund expense; (4) property tax expense; and (5) amortization of intangible assets, and asks that the Department allocate 1.0802% of the test year and proformed costs to non-utility operations. See AG. Br. at 31-32. In fact, while most expenses were appropriately allocated in the original allocation studies conducted for the Electric Division and the Gas Division, the Attorney General is correct on this issue: 4 items had not. Exh. FGE-MHC-7 (Electric) (Gas). The evidence is that FG&E analyzed over 200 individual accounts and subaccounts for allocations, but 4 items were omitted: liability insurance, URT retiree trust fund expense (FAS 106 was properly allocated), property tax associated with the FG&E Service Center in Fitchburg, and amortization of intangible assets. See Exh. FGE-MHC-7.

First, with regard to property insurance, FG&E did present evidence that property insurance was in fact allocated, based on a ratio of non-utility gross plant to total gross plant. Exh. FGE-MHC-1 (Electric) at 068-069; Exh. FGE-MHC-1 (Gas) at 067. In addition, medical and dental expense adjustments and FAS 106 PBOP were correctly allocated in the test year, so contrary to the Attorney General's position, no change is necessary to the level of allocation or to the form of allocator for pro forma adjustments. Exh. FGE-MHC-7 (Electric) (Gas) at Account 926.

However, the hearing process revealed that FG&E had not allocated liability insurance test year expenses (Account 925) to the rental programs as part of the allocation studies. Exh. FGE-MHC-7 (Electric) (Gas). Accordingly, FG&E indicated that the gross plant allocator may be appropriate to allocate liability insurance to non-utility operations, and indicated its intent to do so. See Exh. DOER-RR-07 (Common). Since the filing of that record response, FG&E has determined that the revenue allocator (rather than the gross plant allocator) may have precedential support for allocating "other allocations," including Account 925. Blackstone Gas Co., D.T.E. 01-50 at 12 (2001) (Blackstone's proposal to use revenue allocator deemed "reasonable"). Therefore, FG&E requests that the Department approve its use of the revenue allocator for Account 925 liability insurance costs in the test year. In addition, FG&E proposes to use, and seeks the Department's approval of, the revenue allocator for all pro forma adjustments to all accounts that will be allocated in the compliance filing (e.g. "other allocations").[29]

Second, the Attorney General is correct, in part, that the URT had inadvertently not been allocated to non-utility rental programs for the purposes of the test year revenue requirement; however, FAS 106 PBOP had. Therefore, FG&E requests that the Department approve its proposal to allocate test year amounts for the URT for the test year to each the Electric Division and Gas Division rental programs, as well as pro forma adjustments, in a manner similar to the FAS 106 PBOP. See Exh. FGE-MHC-7 (Electric) (Gas). Finally, neither property taxes on the FG&E Service Center Building (only) nor the amortization of intangible software had been

[29] In other words, for administrative reasons and economy of resources, FG&E asks the Department not to require it to rerun and reallocate test year numbers that have already been allocated using other reasonable allocation factors, but to approve the revenue allocator for those accounts not yet allocated and for all pro forma adjustments.

allocated to non-utility operations for the purposes of determining the test year revenue requirement. FG&E believes it is appropriate, and therefore FG&E proposes, to allocate both of these accounts to non-utility operations for the Electric Division and the Gas Division following the Blackstone Gas precedent, thereby using a revenue allocator to allocate the test year amount and all pro forma adjustments, and FG&E seeks Department approval of the same.

p. Operating Lease (Common)

FG&E proposes to include $132,824 in Electric Division operating expense and $69,820 in Gas Division operating expense to reflect the test year and pro forma operating expenses of the FG&E Service Center, located on John Fitch Highway in Fitchburg. DTE-RR-6, updated 10/02/02 at Sch. MHC-7-20 (Electric) and Sch. MHC-7-21 (Gas); DTE-RR-41. As discussed infra, FG&E seeks to reverse its initial treatment of capitalized lease cost in rate base, and to include the operating rent expense for that facility in the Electric Division and Gas Division O&M Expense. Id. (steps for reversal provided in DTE-RR-6, updated Sch. MHC-20 (Electric) (Gas). A utility's rent expense represents an allowable cost qualified for inclusion in a utility's overall cost of service. Nantucket Elec. Co., D.P.U. 88-161/168 at 123-125 (1988); see also, New England Tel. & Tel. Co., D.P.U. 86-33-G at 23-34. Therefore, this proposal is consistent with Department precedent and should be allowed.

3. Other Issues

a. Meter Removal (Electric)

The Attorney General has attempted to manufacture an argument that FG&E is improperly accounting for its costs of meter removals. AG Br. at 37-38. There is nothing sinister or incorrect about FG&E's accounting practices. In fact, consistent with NARUC/FERC and the Department's Uniform System of Accounts, FG&E follows the prescribed method for accounting for the expensing of the costs of removing and resetting meters. The precedent of expensing all removal costs relative to electric and gas meters is long established, is followed by most of, if not all, Massachusetts utilities, and has been tacitly accepted by the Department for several years See Re Commonwealth Electric Co., D.P.U. 89-114/90-331, 91-80 (July 1, 1991) (Cost of removing and resetting meters in recurring expense properly included in cost of service). Contrary to the Attorney General's characterizations, Mr. Aikman never testified that the cost of meter removal should be capitalized, and there is no evidence in the record that supports the capitalization of these costs. Exh. AG-4-21, for example, states:

> Please see Attachment AG-4-21, page 1 through 81, for a copy of the Uniform System of Accounts for Gas Companies. Located on page 42 of 81 is the directive requiring the expensing of meter removals.

In the depreciation study, Mr. Aikman also notes in his description of Account 381, Gas Meters:

> Zero net salvage is the obvious estimate as the removal of meters is charged as an expense to Account 878, as directed by the DTE.

Exh. FGE-JHA-1 at Sch.-JHA-1 (Gas) at 107.

The Attorney General is confusing two accounts relative to the cost of removing and resetting meters. Plant Account 381, Gas Meters, in the Department's Uniform System of Accounts states, "the cost of removing and resetting meters shall be charged to Account 878, Meter and House Regulator Expense." Disregarding this provision, the Attorney General points to Account 254, Reserve for Depreciation of Utility Plant in Service, which states:

> At the time of retirement of depreciable utility plant in service, this account shall be charged with the book cost of the property retired and the cost of removal . . . ."

Accordingly, the Department should accord no weight to the Attorney General's allegation relating to FG&E's accounting for meter removal.

b. Incentive Compensation (Common)

The Attorney General complains that FG&E's employee incentive programs costs should be excluded from the cost of service because the adjustment is "based on shifting goals and are not measurable and known." AG Br. at 36. Specifically, the Attorney General argues that the part of the payroll adjustment resulting from the earnings goal (30%), the new business incentives goal (20%) and the subjective evaluation goal (20%) should be excluded. According to the Attorney General, these goals are unreasonable because he alleges they are inherently subjective. Id. at 37. The Attorney General misapprehends the "known and measurable" standard. The test year amounts that FG&E expended in the test year for each of its incentive programs are known, have been quantified and have been appropriately reflected in the test year cost of service. The fact that the incentive goals may be adjusted from time to time by company management does not alter the fact that the costs are recoverable. Business judgment is applied to several cost items, such as outside vendors, for example, that are known and measurable and are also included in the cost of service.

In Massachusetts Elec. Co., D.P.U. 89-194/195 (1990), the Department determined that an incentive compensation plan may be included in revenue requirement if it is (1) reasonable in amount; and (2) reasonably designed to encourage good employee performance. See also Boston Gas Co., D.P.U. 93-60 at 98-99 (1993). The Department has also decided that properly designed and administered incentive compensation programs should include quantifiable benchmarks for performance, defined goals and reasonable performance goals. Bay State Gas Co., D.P.U. 92-111 (1992). A reasonably designed incentive program with these parameters will benefit firm ratepayers by the avoidance of additional salary expense and reducing company costs. See id.[30]

[30] A reasonably designed program will encourage good employee performance and result in benefits to ratepayers. Boston Gas Co., D.P.U. 93-60 at 99.

The record does not support the Attorney General's charge that FG&E changed the goals during the test year. Compare AG Br. at 36 with Exh. DTE-4-9. Furthermore, as stated in the Plan, the Board of Directors establishes Incentive Plan Goals each year at the beginning of the year. Exh. DTE 4-9. This allows the Company to be responsive to both the needs of its ratepayers and its shareholders. Once the PBR takes effect, for example, goals that are directly related to PBR performance measures will receive greater weighting in the Incentive Plan. This is a direct benefit to ratepayers.

The premise of any Incentive Plan is that properly compensated employees directly benefit customer by providing better service at better costs. Without proper, fair and adequate compensation, a company would experience high turnover and unqualified employees providing inadequate service. In addition the Incentive Plan was developed to make FG&E's cash compensation program more competitive. See Exh. DTE 4-5 (Confidential). The Directors chose goals which are measurable from year-to-year and which adequately recognize the contributions of all employees towards the success of FG&E.

During the test year, the two Incentive Compensation Plans had the following goals: (1) Earnings (40% normalized); (2) Service Reliability (10%); (3) Low Distribution Cost (10%); (4) Customer Satisfaction (10%); (5) Usource (10%); and (6) Subjective Evaluation (20%). Exh. DTE-4-9, Attachment 1, Attachment 3 (Subjective evaluation includes regulatory outcomes). Appropriately analyzed, the incentive plan strikes an appropriate balance.[31] Management's focus on shareholder earnings cannot take precedence; they must be equally concerned with service reliability, customer cost and customer satisfaction. Exh. DTE 4-9, Attachment 1, Attachment 3.

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[31] The Attorney General is confused by the evidence. Exh. DTE 4-9 Attachment 1 is the Employee Incentive Compensation Plan. Exh. DTE 4-9 Attachment 2 is the Management Incentive Compensations Plan. Attachment 3 shows how the Plans met their targets in 2001. DTE 4-9.

In addition, the Board evaluates all of these measures when considering the subjective element of the incentive award. Tr. 9/6/02 at 1604-1621.

The record contains evidence to support the reasonableness of each of these measures. Tr. 9/6/02 at 1604-1622. The "core utility earnings" measure is important, because it includes only utility operations. Tr. 9/6/02 at 1613. In a performance based rate program, which FG&E expected to implement on two separate occasions in the last two years, earnings versus service measures is a critical skill reflecting good management. It also provides clear benefits to ratepayers.

"Service Reliability" measures historical service standards against performance, and rewards evidence of improved reliability in service to customers. Tr. 9/6/02 at 1614. "Low Cost" measures cents per kWh for service. This measures the cost to provide service in a given year, divided by the number of kWh sold. Id. Customers benefit when reliability is high and service cost is low, and these measures are reasonable.

"Customer Satisfaction" measures how FG&E is fairing in areas of customer service, customer education, customer assistance, among others. Tr. 9/6/02 at 1605. This measure, as well, directly benefits customers, by ensuring the Company is addressing their needs and concerns.

With regard to the Attorney General's complaints relative to the Board's "Subjective Evaluation," as Mr. Collin explained, this evaluative piece acts to put a cap on the incentive award. Tr. 9/6/02 at 1617-1618. If the other five measures stood alone, and the measures were met, an employee would receive 100% of the Plan award (5% of his/her base salary). Exh. DTE 4-9, Attachment 1, p. 1. Because both incentive compensation plans hold back 20% as discretionary, all measures could be met, but the Board may decide to pay only 80% of the award (less than 5%) in light of other facts. See Tr. 9/6/02 at 1617-1620 (awards reduced because of regulatory outcomes).

Accordingly, the construct of the Plan is clear in the record, is reasonable in scope and amount, and benefits ratepayers. The Plan complies with Department precedent and should be approved.

D. TAXES OTHER THAN INCOME

1. Payroll Taxes

The Department has consistently allowed FICA and Medicare payroll tax expense adjustment in revenue requirements as these relate to associated payroll adjustments. This adjustment calculates the increase in FICA and Medicare payroll taxes related to the proformed increase in payroll. Exh. FGE-MHC-1 (Gas) at 067; Exh. FGE-MHC-1 (Electric) at 069. DTE-RR-6 (Electric) updated 10/02/02 at Sch. ADJ (Electric), line 13; DTE-RR-60 (Electric). The adjustment increases test year Gas Division payroll taxes by $7,980 and increases Electric Division Payroll Taxes $7,626. DTE RR-6 (Gas) (Electric), updated 10/02/02 at Sch. ADJ (Gas), line 12; Sch. MHC–7-18 (Gas), line 20; Sch. MHC-7-15 (Electric), Line 21; DTE-RR-60 (Gas).

2. Property Taxes

FG&E proposes an increase to its test year property tax expense of $128,062 for its Electric Division and $166,327 for its Gas Division. The Department's established precedent is to determine the reasonable level of property tax expense in rates on the latest property tax bills a utility receives from the cities and towns that it serves while the rate proceeding is pending. D.T.E. 99-118 at 56; Boston Gas Co., D.P.U. 96-50 (Phase I) at 109; Boston Gas Co., D.P.U. 93-60, at 220 (1993).

As an initial matter, FG&E based its proposed property tax adjustment for the Gas and Electric Divisions on the latest property tax bills received by FG&E at the time of the filing of the rate cases, those bills received through March 22, 2002. Exh. FGE-MHC-1 (Electric) at 071; Exh. FGE-MHC-2G (Electric); Exh. FGE-MHC-1 (Gas) at 069; Exh. FGE-MHC-2E (Gas); Exh. AG-5-41 (Gas). FG&E will update the property tax adjustment on October 24, 2002, coincident with FG&E's Reply Brief based on the latest property tax bills received at that time. DTE-RR-6 (Gas) (Electric), updated 10/02/02; Exh. FGE-MHC-2E (Gas); see also Exh. FGE-MHC-2G (Electric).

Mathematically, the adjustment to test year property tax expense for the Electric Division and for the Gas Division was based on the annualized amounts of property tax bills received from municipalities. Exh. FGE-MHC-1 (Electric) at 071 (bills were those received by time of filing); Exh. FGE-MHC-1 (Gas) at 069. A capitalized amount was then subtracted to determine the amount charged to expense. Id. The adjustment then calculated the expense related to Gas Division operations and Electric Division operations on an allocated basis. Id.; DTE-RR-6 (Electric) (Gas) updated 10/02/02 at Sch. MHC-7-16 (Electric), Sch. MHC-7-19 (Gas).

The derivation of the allocation between the Gas and Electric Divisions was determined as a result of the G/E Split Study that was performed on all common costs for the test year. Exh. FGE-MHC-6 (Electric) (Gas). The allocated amounts were compared to the test year property tax expense for the Gas and Electric Divisions, resulting in a proposed increase in property tax expense for the Electric Division of $128,062, and a proposed increase in property tax expense for the Gas Division of $166,327. Sch. MHC-7-16 (Electric), line 15, and Sch. MHC-19 (Gas), line 15.

E. AMORTIZATION EXPENSE

In its initial filings for the Electric Division and the Gas Division, FG&E examined various amortizations recorded per books for the Electric Division and for the Gas Division. Exh. FGE-MHC-1 (Electric) at 072; Exh. FGE-MHC-1 (Gas) at 070. The amortization expense adjustment that the record demonstrates as appropriate for the Electric Division is $192,547. DTE-RR-6 at Sch. ADJ (Electric), line 4; compare Exh. FGE-MHC-1 (Electric) at 072 with Sch. MHC-7-18 (Electric); Exh. DTE-7-32; Exh. DTE-7-24. The amortization expense adjustment that the record demonstrates as appropriate for the Gas Division is $82,011. DTE-RR-6 at Sch. ADJ (Gas), line 4; compare Sch. MHC-Exh. FGE-MHC-1 (Gas) at 070 with Sch. MHC-7-21 (Gas); Exh. DTE-7-32; Exh. DTE-7-24.

The amortization amount has changed from the initial filings in order to reflect refining adjustments made during the proceeding. DTE-RR-6 at Sch. ADJ (Electric), line 4; compare MHC-Exh. FGE-MHC-1 (Gas) at 070 and Sch. MHC-7-21 (Gas); Exh. FGE-MHC-1 (Electric) at 072 and Sch. MHC-7-18 (Electric); Exh. DTE-7-32; Exh. DTE-7-24. In particular, FG&E reclassified the amortization expense attributable to LERS/Logica from an allocation between Gas and Electric Division to an assignment entirely and solely to the Electric Division. DTE-RR-6 at Sch. ADJ (Electric), line 4; Exh. DTE 1-12; DTE-RR-5.

With regard to FG&E's amortization of the remaining costs of D.T.E. 99-118 as part of its Electric Division cost of service, FG&E recognizes that the Department's precedent has provided that regulatory litigation expense be normalized so that a representative amount is included in the cost of service. D.T.E. 98-51 at 53; Massachusetts Elec. Co. D.P.U. 95-40 at 56 (2002). Upon review, FG&E's proposed amortization is beyond the established precedent. However, FG&E believes that, under the facts, it is just and reasonable, and the Department should permit the proposed amortization. It is expected that a periodically recurring expense is under a utility's control. See Mass-American Water Co., D.T.E. 95-118 at 122 (1995).

FG&E reasonably incurred these costs, not only in a litigated rate proceeding, but in a litigated proceeding that took place in the test year. Moreover, it was not even a full rate case: it was a rate review with a more limited scope. D.T.E. 99-118 (2001). Additionally, as a Chapter 93 proceeding initiated by the Attorney General, the choice of filing or not filing the case was stripped away from FG&E. FG&E did not choose to file a rate proceeding in 2001: it chose to file a rate proceeding in 2002. Failing to include the unamortized balance of these litigation costs is tantamount to saying that FG&E never had the opportunity to recover them at all. FG&E's goal is a Department ruling consistent with the regulatory policy of sharing the burdens and benefits of rate litigation between shareholders and ratepayers. Accordingly, FG&E believes that the amortization of the D.T.E. 99-118 litigation costs is appropriate.

With regard to the remaining amortizations, in particular software, CIS, and web site design, the Department has found that technological improvements, particularly with regard to software systems, may render these systems obsolete after a short periods of time. Massachusetts Elec. Co., D.P.U. 95-40 at 63 (1995), citing Boston Gas Co., D.P.U. 93-60-D at 4 (1994). Furthermore, excessive lengthy amortization periods discourage utilities from innovations that improve service to customers. Id. The Department has accepted 5 year amortizations for software products as reasonable. Id.

The Attorney General complains that FG&E's amortizations are inconsistent, but is so vague in his allegations that FG&E can scarcely respond. AG Br. at 24. Where the Attorney General claims that an amortization did not commence in the year of purchase or upgrade, the record demonstrates that the year of purchase cannot automatically be deemed the year in service or when useful life commenced. Compare AG Br. at 24 with Tr. 8/19/02 (Vol. 8) at 923, 926-27 (cost deferred in development stage, but amortized over useful life); AG-RR-26 (MVRS site license is an upgrade and licensing process for user stations). The Attorney General seems confused. In fact, a good proportion of the proposed amortizations for the Electric Division are the same amortizations made in D.T.E. 99-110, when FG&E requested to recover these costs as part of its electric rate reconciliation mechanisms. There, the Attorney General claimed, and the Department agreed, that they would be more appropriately recovered in base rates for the Electric Division. Tr. 8/19/02 (Vol. 8) at 927. Accordingly, FG&E reclassified these intangible assets for amortization within the distribution function in 2001, the year of the Department's Order. Id. at 923-27. The Attorney General should not be surprised to see these amortizations now, in kind or amount.

While the Attorney General claims FG&E used "inconsistent amortization periods," each of which is buttressed by record evidence, the Attorney General did not challenge the reasonableness of any particular addition, or the length of amortization proposed. FG&E provided extensive documentation about the allocations, the nature of the amortizations and the justification for their amortization periods. Exh. DTE -1-2; Exh. DTE-7-32; Exh. DTE-7-24; DTE-RR-49; DTE-RR-51; DTE-RR-5; AG-RR-26. Each of FG&E's proposed amortizations for its Electric Division and its Gas Division is reasonable in amount and in length, and should be approved.

F. INCOME TAXES

FG&E computed Massachusetts Franchise Taxes and Federal Income Taxes using the rate base and rate of return methodology in accordance with the Department standard. Exh. FGE-MHC-1 (Electric) at 073; Exh. FGE-MHC-1 at Sch. MHC-5 (Electric); Exh. FGE-MHC-1 (Gas) at 070; Exh. FGE-MHC-1 at Sch. MHC-5 (Gas).

In addition, the computation provides for the amortization of the net regulatory asset resulting from the application of Statement of Financial Accounting Standards (SFAS) 109, "Accounting for Income Taxes," relating to both Federal income and Massachusetts Franchise Tax. Exh. FGE-MHC-1 (Electric) at 073; Exh. DTE-4-16. In 1992 the Financial Accounting Standards Board issued Statement No. 109, "Accounting for Income Taxes" (FAS 109). FAS 109 required companies, effective December 31, 1992, to record on their financial statements all future income tax liabilities. See e.g. Exh. FGE-MHC-1 (Electric) at 073-074; Exh. FGE-MHC-1 (Gas) at 071; Exh. DTE-4-16. FAS 109 requires the use of the asset/liability method of accounting for deferred income taxes on all temporary timing differences. Exh. DTE-4-16. When FG&E adopted FAS 109, it determined the deferred tax liability applicable to the differences between its tax balance sheet and its book balance sheet. It then compared the deferred tax liability calculated under FAS 109 to the deferred taxes recorded on its books. The tax/book balance sheet differences principally resulting from the prior flow-through were grossed up to measure the revenue impact. FG&E then recorded (1) these regulatory assets and liabilities, (2) the previously unrecorded deferred tax liability and (3) the deferred tax effect associated with FAS 109 regulatory assets and liabilities, which are also temporary timing differences. Exh. DTE-4-16. Because utilities subject to cost of service ratemaking are allowed to recover income tax liability in rates, they were allowed to record an offsetting net regulatory asset representing the future recovery of the income tax liability in rates. Exh. FGE-MHC-1 (Electric) at 073-074; Exh. FGE-MHC-1 (Gas) at 071. FG&E has been recording the net regulatory asset and future tax liability related to Federal and State income taxes since December 31, 1992. Exh. FGE-MHC-1 (Electric) at 073-074; Exh. FGE-MHC-1 (Gas) at 071.

The Department authorized the recovery of the FAS 109 net regulatory asset related to FG&E's electric operations over a 20-year period. D.T.E. 99-118 at 57; Exh. AG-7-29; see, Exh. AG-5-29. The amount of such authorization related to transmission/distribution operations was $260,913. Exh. FGE-MHC-1 (Electric) at 073; Exh. FGE-MHC-1 at Sch. MHC-5 (Electric). The test year-end balances of the FAS 109 Regulatory Assets, FAS 109 Regulatory Liabilities and Accumulated Deferred Income Tax (ADIT) Liabilities are included as part of FG&E's revenue requirement. Exh. FGE-MHC-1 at Sch. MHC-11 (Electric); Exh. FGE-MHC-1 at Sch. MHC-11 (Gas).

Because of the similarity of the analysis applicable to both electric and gas regulatory assets in this context, it is reasonable to have equivalent treatment of the net regulatory assets in both the Gas Division and the Electric Division. Exh. FGE-MHC-1 (Electric) at 073-074; Exh. FGE-MHC-1 (Gas) at 071. Therefore, FG&E proposed similar recovery of the Gas Division distribution net regulatory asset. The amount of the amortization of the net regulatory asset relating to both Federal and Massachusetts Franchise Tax is $129,825 and is included in the Gas Division revenue requirement. Exh. FGE-MHC-1 (Gas) at Sch. MHC-5 (Gas). The amortization is based on a 20-year period applied to the balances of net regulatory assets as of December 31, 2001. Exh. FGE-MHC-1 (Gas) at Sch. MHC-5 (Gas). The test year-end balances of the SFAS 109 Regulatory Assets, FAS 109 Regulatory Liabilities and ADIT Liabilities are included, as they are on the Electric Division FAS 109 calculation. Exh. FGE-MHC-1 (Gas) at Sch. MHC-11 (Gas), lines 17-22.

As described in Section V.A.4(a), on October 2, 2002 FG&E adjusted the allocation between the Electric and Gas Division of FAS 109 regulatory asset, FAS 109 regulatory liability and FAS 109 Accounting for Income Taxes. These adjustments changed the test-year amount of the Gas Division net regulatory asset subject to amortization from $2,596,492 to $2,990,862. As a result, the related annual amortization changed from $129,825 to $149,543. DTE-RR-6, updated 10/02/02 at Sch. MHC-5 (Gas).

VI. RATE STRUCTURE

In order to satisfy the Department's long-standing rate structure goals, rate design must produce a set of rates for each rate class that match the cost of serving that class (absent considerations of rate continuity), and to the extent possible, the rate design should be set on marginal cost. Boston Gas Co., D.P.U. 93-60 at 368 (1993). To support its Electric Division rate structure and its Gas Division rate structure, FG&E presented the expert testimony of James L. Harrison of Management Applications Consulting, Inc. See Exh. FGE-JLH-1 (Electric); Exh. FGE-JLH-1 (Gas). Mr. Harrison developed the accounting and marginal cost of service studies for the Electric Division and provided class revenue targets used in the proposed rate design. Exh. FGE-JLH-1 (Electric) at 003; Exh. FGE-JLH-1 (Gas) at 003.

A. Issues Unique to Gas Division

1. Weather Normalization Study

Weather Normalization is conducted for the purposes of rate making, because the test year must "represent typical or normal circumstances." Exh. FGE-JLH-1 (Gas) at 004. FG&E's Gas Division sales are weather sensitive, such that even small variations in weather may materially impact sales and revenues. Exh. FGE-JLH-1 (Gas) at 004. Normal weather is defined according to Department precedent, that it should equal the average anticipated degree days over the last 20 years. Colonial Gas Co., D.T.E. 98-90, at 6 (2000); Berkshire Gas Co., D.T.E. 98-99, at 8 (1999); Essex County Gas Co., D.P.U. 93-95, at 6(1996).

In calculating the factor for weather normalization, Mr. Harrison summed the most recent 20 years of monthly data, averaging each month to derive the expected monthly degree days in a normal year. Exh. FGE-JLH-1 (Gas) at 005. In the course of the proceeding, Mr. Harrison recognized a minor error in his calculations and provided corrected figures for subsequent use. DTE-RR-14 (Gas). The adjustment is reasonable and appropriately calculated.

First, Mr. Harrison summarized the weather normalization calculations by taking monthly per-books bill count data for 2001 and sales in therms, revising the per-books numbers for appropriate test year billing adjustments. Exh. FGE-JLH-1 (Gas) at Sch. JLH-2 (Gas); Exh. FGE-JLH-1 (Gas) at 005. Mr. Harrison also derived the billing cycle degree days including actual and 20-year normal degree days by calendar month. Exh. FGE-JLH-1 (Gas) at 006. He made volumetric adjustments resulting from weather variations and calculated the adjustment for each of the ten customer classes, segregating sales from transportation classes, following Department precedent. See Exh. FGE-JLH-1 at Sch. JLH-2 (Gas). Monthly sensitivity to degree day variations were computed by dividing the heating load by the actual billing cycle degree days to derive the actual unit heat load per degree day. See Exh. FGE-JLH-1 at Sch. JLH-2 (Gas).

Mr. Harrison proposed a minor change to Department precedent in computing heating loads. Traditionally, heating load was computed as total sales less base use, computed as the number of customers times the average use per customer for the months of July and August. Mr. Harrison pointed out that July usage is often depressed by plant shutdowns and therefore including July results is an understatement of base use. He recommended that base use should be computed as the average of August and the lower of June or September when July usage is artificially low. Once he developed an appropriate heating use per degree day factor, this figure was then multiplied by the temperature departure from normal to develop a weather adjustment.

See Exh. FGE-JLH-1 at Sch. JLH-2 (Gas). The result was an increase to sales as a result of weather. See Exh. FGE-JLH-1 at Sch. JLH-2 (Gas).

2. Development of Billing Determinants

Billing determinants were created by examining number of customers, calendar month sales and, for the large customer classes, weather normalized billing demands for each class, segregated between sales and transportation service. See Exh. FGE-JLH-1 at Sch. JLH-3 (Gas) (Billing month degree day calculation).

3. Market Based Allocation ("MBA") of Gas Cost

FG&E created the CGAC using the Market-based Allocation methodology. Exh. FGE-JLH-1 at 010 (Gas); Exh. FGE-KMA-1 at 359 (Gas). The weather adjusted test year gas costs were used to develop the direct gas cost allocations, in accordance with Department precedent. Berkshire Gas Co., D.T.E. 01-56 at 131; D.T.E. 98-51 at 135; Eastern Edison Co., D.P.U. 1580 at 13-14 (1984).

The MBA method identifies and separately assigns costs to the portion of the system load curve that can be served at extremely high annual firm load factors; it assigns average, pipeline delivered costs to the loads of the individual customers that make up the block. Exh. FGE-JLH-1 (Gas) at 010. Accordingly, under MBA, the capacity and commodity costs of gas slated for injection into storage and their associated transportation costs are accumulated and assigned to the winter period. Exh. FGE-JLH-1 (Gas) at 011.

The MBA method also addresses the allocation of capacity and commodity costs to the portion of the system load curve that remains after this high load factor block is served. Exh. FGE-JLH-1 (Gas) at 011. These remaining loads are primarily firm winter loads. Exh. FGE-JLH-1 (Gas) at 011.

Mr. Harrison made one minor enhancement to the method of allocating remaining demand costs that account for 15% of the total test year gas cost. Exh. FGE-JLH-1 (Gas) at 012. Rather than allocate costs to months and then classes, Mr. Harrison recommends allocating costs to classes and then to months, as the Department approved previously. Exh. FGE-JLH-1 (Gas) at 012-013; Berkshire Gas Co., D.T.E. 01-56 at 125. Therefore, Mr. Harrison employed a design day allocator less that portion of load served by base use supplies to assign costs to classes and then the Proportional Responsibility ("PR") method to distribute costs to months. Exh. FGE-JLH-1 (Gas) at 013.

Once annual remaining capacity costs are assigned to classes, the MBA method develops a single PR allocator based on the remaining load block in a normal year. The PR allocator is applied to the total remaining capacity cost of each class to assign costs monthly, resulting is slightly higher unit costs to the higher load periods. Exh. FGE-JLH-1 (Gas) at 012. Remaining monthly commodity costs were computed residually after serving the base use block. Exh. FGE-JLH-1 (Gas) at 012. Test year total costs by source were reduced for base load commodity, and remaining costs were assigned to serve customer classes in proportion to their remaining usage. Exh. FGE-JLH-1 (Gas) at 012.

4. Response to the Attorney General

The Attorney General begins his argument by advocating that the Proportional Responsibility Method, and not the Design Day allocator, is more appropriate to allocate remaining supply capacity costs (capacity costs remaining after base use supplies are allocated to base use consumption). AG Br. at 66. However, the Attorney General is advocating the PR Method in the face of established Department precedent: The Attorney General has made this same argument in the recent past, but the Department approved a change from a PR allocator to a design day allocation for capacity cost causation. Berkshire Gas Co., D.T.E. 01-56 at 128.[32] Moreover, the Department has decided that Design Day is also an appropriate allocator for capacity assignment. D.T.E. 98-32-B at 12. The Department has stated a goal that capacity assignment procedures should protect sales customers from gas price changes due to migration. D.T.E. 98-32-B at 31. Design Day allocation meets this goal.

There is irony in the Attorney General's current position: He argued against a version of the MBA using the PR allocator in FGE's last rate case, D.T.E. 98-51. Now, inexplicably, he argues that that method should be retained. Nor does the Attorney General's attempt to avail himself of the testimony of Mr. Collin to support his claim that the PR allocator is appropriate in place of Design Day. AG Br. at 67. Mr. Collin was discussing the operational availability and use of FG&E's LNG facilities at certain times in the winter, not about cost causation principles. Tr. 9/4/02 (Vol. 12) at 1484.

Even if FG&E were to accept, arguendo, the Attorney General's conclusions regarding the use of the PR allocator, the hypothetical example he posits contradicts his position. See AG Br. at 67-68. If the normal year peak could be met with storage alone, both the older PR version of the MBA, and that proposed for this docket, would allocate local production resources (that are undispatched in the normal year) on the basis of a Design Day allocator. Furthermore, where the Attorney General asserts "[n]one of these slices [of different types of capacity] resemble a marketer's portfolio," AG Br. at 66, there is no basis in fact or on the record to substantiate this argument. Mr. Harrison's testimony as well as simple logic contradict it: since mandatory capacity assignment is made on this same slice of the system basis, marketers' portfolios must resemble the capacity assignment resulting from a Design Day allocation.

32 In replying to this argument, FG&E is aware that the arguments presented by the Attorney General on the first half of page 66 are unsubstantiated opinions and should be stricken. They are confused and misleading and have no record support.

The Attorney General's argument claiming that the design day allocation that Mr. Harrison used for the rate case differs from that for capacity assignment is a red herring. The Attorney General also indicates that the Company did not make clear its CGAC methodology until after August 15. AG Br. at 69. The Attorney General confuses the issue. The focus of the Company's proposal is a change to its CGAC methodology which was made clear in its initial filing. Exh. FGE-JLH-1 (Gas) at 10-12; Exh. FGE-KMA-1 (Gas) at 359. The Company proposes a modification to its MBA methodology such that remaining demand costs are allocated based on design day instead of the PR method. The purpose of the rate design proposed by FG&E is to approve the change to the Design Day allocator. The actual computation of design day is not a rate case issue. Nevertheless, any differences in the design day calculations are very minor. AG-RR-20; Tr. 8/13/02 (Vol. 5) at 674.

Furthermore, the Company plans to utilize the same design day calculations in its CGAC currently employed for its capacity assignment calculations. The record is muddled because the Attorney General concentrated on whether the Company will utilize Mr. Harrison's methodology. Tr. 8/13/02 (Vol. 5)at 674, 677; AG-RR-18. For the compliance phase in this docket and in future CGAC filings, the Company will use the same calculations for design day that will be used for its annual capacity assignment filing with one minor distinction, which was not made on the record. The capacity assignment calculations are based on total load, including firm sales and non-grandfathered firm transportation customers. Since the CGAC calculations rely on firm sales customers only. The design day calculation will include firm sales customers only. The CGAC filings will show this distinction, so there will be no inconsistency. The capacity assignment calculations are performed and filed annually for Department review and approval pursuant to FG&E's model Terms and Conditions. AG-RR-46.

The Attorney General confuses the two different calculations. AG Br. at 69. The first calculation is made to determine the percentages of pipeline, storage, and peaking resources used to satisfy class (not individual customer) design day demands. This calculation is forward-looking, using normalized data based on the same 12 month period used to establish the cost data for the CGAC filing. The second calculation, using 18 months of historical data, is used to determine the individual customer's design day demand. The class design day demand calculations will be the same for the CGAC and the capacity assignment calculations. Thus, there is no inconsistency.

In advancing his position, the Attorney General misconstrues the record evidence. AG Br. at 69. To clarify, there are two separate calculations for capacity assignment: (1) the development of class percentages for pipeline, storage and peaking resources, and (2) the determination of the customer's individual demand. The posted percentages and unit costs for capacity assignment come from a class allocation similar to Mr. Harrison's (and which method will be identical in future CGAC filings as noted above). The magnitude of the individual customer's demand, required for individual capacity assignments, was not calculated by Mr. Harrison. But even this method used the same regression techniques employed by Mr. Harrison. The Attorney General also argues that a change to design day would introduce unnecessary complexity and reviewability. AG Br. at 69. However, the problem is moot if the same design day calculations already used and approved by the Department for capacity assignment are used for the CGAC.

B. Accounting Cost of Service Study ("COSS")

Because the cost to serve the customers of any utility company consists generally of operating expenses and return, the Department examines historical test periods to determine the overall cost to serve the customers of the utility. This is called the "revenue requirement."

However, as Mr. Harrison described, the unique cost to serve customers of the various service classes is more difficult to determine, because costs can vary significantly between customer classes depending upon the nature of class demands upon the system and the facilities required to serve them. Exh. FGE-JLH-1 (Electric) at 004. Therefore, the purpose of an Allocated Cost of Service Study (COSS) is to assign or allocate each relevant component of cost on an appropriate basis in order to determine the proper cost to serve the respective classes, in accordance with Department precedent. Exh. FGE-JLH-1 (Electric) at 004.

1. Electric Division and Gas Division COSS

In order to create FG&E's COSS, Mr. Harrison developed a cost model for FG&E's operations. Exh. FGE-JLH-1 (Electric) at 004; Exh. FGE-JLH-1 at Sch. JLH-1 (Gas). Using this model, Mr. Harrison was able to examine each element of Rate Base, Revenue and Operating Expense in detail and to assign or allocate each item to a customer class. Exh. FGE-JLH-1 (Electric) at 004-005; Exh. FGE-JLH-1 (Electric) at Sch. JLH-2-1 (Electric) (the results of the class COSS for delivery rates); Exh. FGE-JLH-1 at Sch. JLH-5-2 (Gas).

For the Electric Division, the COSS excludes all Electric Division costs recovered through the Seabrook Amortization Surcharge, the Energy Efficiency Charge, the Renewable Resource Charge, the Transition Charge, the Default Service Charge and the SOS Generation Charge. The study also functionally separates costs. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2-2 (Electric) (functional cost of service study for T&D). In addition, the Electric Division COSS recognizes load diversity in FG&E's distribution system by allocating capacity-related distribution plant such as substations on the average of the twelve coincident peak ("12CP") demands and the class peak demands; poles, conductors and conduit and underground conductors on class peaks; and line transformers on the average of class peaks and the sum of the individual customer maximum demands. Exh. FGE-JLH-1 (Electric) at 007.

For the Gas Division, all supply and delivery costs were included in the cost of service study. By including all supply and delivery costs in the cost of service study (COSS), the study can properly segregate indirect gas costs. Exh. FGE-JLH-1 (Gas) at 010. For example, according to Mr. Harrison, the study can correctly identify uncollectible accounts expense between the gas supply and delivery functions. Exh. FGE-JLH-1 (Gas) at 010. A summary as well as details of indirect gas costs were made part of the record. Exh. FGE-JLH-1 at Sch. JLH-7 (Gas); DTE-RR-25. The model began with each cost item, which Mr. Harrison then examined individually to determine its appropriate functionalization. The transportation component of cost to serve consists solely of the distribution costs and the customer costs incurred by the Gas Division, and the remaining costs are deemed gas-supply related. Exh. FGE-JLH-1 (Gas) at 027; Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas). The costs included in base rates are unbundled and should exclude all production-related costs. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas) (costs are directly comparable to proposed base rate revenues). The Marginal Cost Study ("MCS") details the calculation of pressure support (5.8%) required from production facilities owned by FG&E and the consequent assignment of the appropriate portion of production costs to the distribution function. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas). Working capital associated with gas costs is excluded from the COSS because, as Mr. Collin testified, the portion of working capital associated with gas supply costs should be treated as gas supply-related. Exh. FGE-JLH-1 (Gas) at 029. FG&E proposes to compute these costs with each CGA filing. Exh. FGE-JLH-1 (Gas) at 029. With regard to gas acquisition and dispatch O&M, booked in Account 851, the COSS appropriately removes these costs from the transportation revenue requirement and assigns them to gas supply. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas). Uncollectible accounts expense (Account 904) is segregated between transportation and gas supply functions, using FG&E's billing records to determine the level of write-offs by rate class, and then further allocating these write-offs between supply and delivery functions on the basis of revenue requirements. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas). Legal expenses booked in Account 928 regarding gas acquisition or FERC matters have been assigned to the supply function. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas). Finally, a portion of overhead costs were automatically assigned to gas supply via internally developed allocators. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas); Exh. FGE-JLH-1 (Gas) at 030.

With regard to Electric Division rate base allocation, Mr. Harrison assigned FG&E's transmission plant investment to capacity and allocated it to classes using a 12CP allocation factor, including internal transmission, but excluding external transmission. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2-1 (Electric), at 2. FG&E's Electric Division rate design separates T&D revenue requirements. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2-1 (Electric), at 21.

With regard to Gas Division rate base allocation, Mr. Harrison first allocated FG&E's production plant investment assigning its costs to the capacity component and allocating to classes using the allocators for remaining production capacity. See Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-1 (Gas). Distribution plant allocation factor DISTR is the capacity allocation factor used for the allocation of distribution plant capacity-related costs such as distribution land and land rights, structures and improvements, measuring and regulating station equipment, other equipment and mains. See Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-1 (Gas), at 3. DISTR is based on the PR Method and the normalized monthly system loads carried by the distribution system are weighted so that costs are assigned to months, based on the variation of sales from peak to off-peak months. See Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-2 (Gas); Exh. FGE-JLH-1 (Gas) at Sch. FGE-JLH-8 (Workpapers supporting Sch. JLH-5-2, 5-3 (Gas) at 66-74. These same methods have been employed and accepted by the Department in recent rate cases. D.T.E. 98-51; Berkshire Gas Co., D.T.E. 01-56.

With regard to allocation of costs to serve, the Department's standards in this area are well established, and Mr. Harrison followed them. Mr. Harrison allocated each item on the most appropriate allocation factor and in accord with Department precedent. Exh. FGE-JLH-1 (Gas) at 017.[33]

Allocation of Electric Division costs to serve began with an engineering estimate of the replacement cost new for a typical service for each rate class. The average service cost for each class was adjusted by a services per customer ratio, in order to ensure that the shared services of small customers did not subsidize the shared costs of larger customers and in the development of an appropriate service per customer ratio for Electric Division residential and GD-3 classes. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2 (Electric)(Workpapers supporting Sch. JLH-3 (Electric)), at 22-44. Finally, the Electric Division COSS includes a services allocator, that results from multiplying each class's estimated cost per service by the services per customer ratio and the number of customers in the class. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2 (Electric)(Workpapers supporting Sch. JLH-2 (Electric)), at 110. The resulting values were summed and prorated by a uniform percentage to match the original cost of Electric Division investment shown in FG&E's books. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2 (Electric) (Workpapers supporting Sch. JLH-2 (Electric)), at 110. Mr. Harrison used standard cost allocation procedure described to aggregate costs and prepare a detailed unbundled Electric Division COSS for T&D functions. Exh. FGE-JLH-1 (Electric) at 008; Exh. FGE-JLH-1 at Sch. JLH-2-2 (Electric).

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33 For example, deferred taxes was allocated on PLANT. The cash working capital was developed internally, using a forty five day allowance by totaling operation and maintenance expenses less fuel and purchased gas expense. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-1 (Gas).

The COSS for both the Electric Division and the Gas Division demonstrate that the rates presently in effect generate different rates of return for each class. In the Electric Division, the Residential, Small General Service and Outdoor Lighting rates produce rates of return lower than average. In the Gas Division, with the residential heating class and residential non-heating classes produce the lowest rates of return compared to the average cost to serve. Exh. FGE-JLH-1 (Electric) at 011; Exh. FGE-JLH-1 at Sch. JLH-2-1 (Electric) at 1; Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-1 (Gas) at 1. FG&E's proposed rate designs, therefore, take steps to address this issue. FG&E's Accounting Cost Study was reasonably developed and appropriately executed.

C. Marginal Cost Study ("MCS")

A marginal cost study is conducted in order to estimate the cost of providing an additional unit of service, which information is used in setting rates that promote appropriate consumption decisions and an efficient allocation of society's resources. Exh. FGE-JLH-1 (Electric) at 011-012; Exh. FGE-JLH-1 (Gas). A typical marginal cost estimate contains unitized cost, based on historical data and recent trends, of expanding the local transmission and distribution network to accommodate growth in customers' (or a single customer's) requirements. Exh. FGE-JLH-1 (Electric) at 012; Exh. FGE-JLH-1 (Gas).

1. Electric Division MCS

FG&E's Electric Division MCS excludes all production costs, as irrelevant to the design of T&D rates. Exh. FGE-JLH-1 (Electric) at 012. Mr. Harrison computed the marginal costs to serve each of the Electric Division rate classes based on rate year costs using regression and other statistical techniques and engineering estimates to derive a hypothetical T&D costs of serving an increment of customer load, including the unit costs of adding distribution plant facilities as well as the additional costs for O&M. Exh. FGE-JLH-1 (Electric) at 012. From these factors, the annual revenue requirements were developed for each rate class. Exh. FGE-JLH-1 (Electric) at 012. These costs are stated in terms of customer energy and demand charges. Exh. FGE-JLH-1 (Electric) at 012.

Three different time periods were used in the MCS. Exh. FGE-JLH-1 (Electric) at 013. The coincident peak hour was the period used to measure capacity costs and represents the extreme load on the system each year.[34] The peak period was the period defined as the weekday non-holiday hours from 7 AM to 10 PM. The off peak period was defined as all remaining hours in the year. Exh. FGE-JLH-1 (Electric) at 013. Based on his experience, Mr. Harrison performed a probability of peak analysis using four recent years of hourly load data and verified that the peak period contains over 99% of the probability of peak. Exh. FGE-JLH-1 (Electric) at 013-014; Exh. FGE-JLH-1 at Sch. JLH-3 (Electric), Table 9.

Mr. Harrison's method of measuring transmission capacity costs was based on discussions with planners who indicated that system design was driven by the need to provide adequate capacity at times of peak. Exh. FGE-JLH-1 (Electric) at 015. Long run marginal costs for historical transmission investments were calculated based on individual account Trended Additions less Trended Retirements, using the Handy-Whitman Index. Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Table 10. Mr. Harrison also found that the regression results were sufficiently robust for estimating long-run marginal costs. Exh. FGE-JLH-1 (Electric) at 016.

For ease of measurement, coincident peak demand was employed as the causative factor driving distribution investment. Exh. FGE-JLH-1 at 016. Distribution capacity costs were complicated by the need to expand capacity on both the primary and secondary systems. Exh.

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34 FG&E's peaks are well-balanced between the summer and winter as evidenced by the fact that the peak occurred frequently in both summer and winter seasons. In order to develop a consistent set of historical data, the historical actual peaks were adjusted to remove Princeton Paper. Exh. FGE-JLH-1 (Electric) at 013.

FGE-JLH-1 (Electric) at 016. Many of FG&E's large customers take service at the primary voltage level and do not benefit from the existence of secondary lines. Exh. FGE-JLH-1 (Electric) at 016. Accordingly, costs for primary and secondary facilities were carefully segregated in the MCS. In order to accurately estimate current marginal costs from historical distribution investments, the historical capacity-related additions were identified and restated using the Handy-Whitman Index for Public Utility Costs. Exh. FGE-JLH-1 (Electric) at 016. Mr. Harrison also found that neither the regression results for both Primary and Secondary were sufficiently robust and, instead, relied on long run incremental average costs for estimating long-run marginal costs. Exh. FGE-JLH-1 (Electric) at 016.

Marginal transmission O&M expenses were estimated using the average unit cost over the past three years. Exh. FGE-JLH-1 (Electric) at 017. Distribution O&M costs are segregated between capacity and customer cost components, with capacity costs further divided between primary costs and secondary costs. Exh. FGE-JLH-1 (Electric) at 017. As Mr. Harrison admitted, marginal distribution O&M expenses were estimated using three year average unit cost since the regressions were relatively weak. Exh. FGE-JLH-1 (Electric) at 017; Exh. FGE-JLH-1 at Sch. JLH-3 (Electric), Table 6.

The marginal capacity costs for T&D functions were developed by grossing up plant investments to include general plant, adding annual operating expenses and an allowance for working capital. Exh. FGE-JLH-1 (Electric) at 017; Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Table 9. Next, the indicated unit costs were increased to reflect unaccounted for losses experienced and these costs were escalated from test year to rate year levels. Id.

The long-run marginal costs of serving an additional customer were determined to be a function of the size of the customer and the class of service. Exh. FGE-JLH-1 (Electric) at 018.

Three different customer costs were computed for (1) plant investment in services and meters; (2) related O&M expenses; and, (3) billing costs such as customer accounting and information expenses. Exh. FGE-JLH-1 (Electric) at 018; Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Tables 3 and 7. The average replacement costs new for each customer class were computed and factored by the services-per-customer ratio. Exh. FGE-JLH-1 (Electric) at 018. Meter investment was developed from estimates created by FG&E's engineering staff. Exh. FGE-JLH-1 (Electric) at 018. The cost of installed meters was factored by a meters-per-customer ratio. Exh. FGE-JLH-1 (Electric) at 018.

The calculations of service and meter-related customer O&M were made by restating them, using a current cost index, regressing that expense against customers and at the same time, regressing the average cost against the time series. Exh. FGE-JLH-1 (Electric) at 018. Because both regressions showed little correlation, the more recent three year average cost was deemed a reasonable estimate of marginal costs to serve a new customer. Exh. FGE-JLH-1 (Electric) at Sch. JLH-3, Table 019. Separate calculations were made for the customer costs related to customer accounting and customer information expenses. Again historical costs were restated to current prices. In this case, the time series regression of the average cost per customer was deemed sufficiently robust to be used for the average marginal customer-related costs. The derived marginal customer costs per year were assumed to be different for each customer class. Exh. FGE-JLH-1 (Electric) at 019. Mr. Harrison used the causal relationships from the COSS to compute marginal customer costs for each customer class. Exh. FGE-JLH-1 (Electric) at Sch. JLH-2-1 (Electric), Table 7.

The marginal customer-related costs per class were developed as part of the MCS, as were loading factors, which were used to compute estimates of marginal cost where direct quantification techniques were unreliable. Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Table 11, Table 8. Mr. Harrison also developed levelized fixed charged rates for peaking production facilities, capacity-related distribution plant and customer-related distribution plant, as well as transmission capacity-related investment. Exh. FGE-JLH-1 at Sch. JLH-3 (Electric), Table 8; Exh. FGE-JLH-1 (Electric) at 020.

With regard to uncollectible expense, Mr. Harrison conducted a separate analysis of uncollectible costs. Exh. FGE-JLH-1 at Sch. JLH-2-1 (Electric), Table 7, at 5. By applying uncollectible percentages by class to the functional revenue requirement for supply, a portion of uncollectible accounts expenses was functionalized as electric supply-related. Exh. FGE-JLH-3 (Electric), Table 12.

The long-run marginal costs properly constructed reveal the revenues that would be generated if FG&E turned to full marginal cost-based pricing and at the same time, customers were inelastic in consumption. Exh. FGE-JLH-1 (Electric) at 022; Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Tables 8, 9, 10, 11, and 12. In addition, the MCS also demonstrates the unit costs based on billed sales in the peak and off-peak periods. Exh. FGE-JLH-1 (Electric) at 022; Exh. FGE-JLH-1 (Electric) at Sch. JLH-3 (Electric), Table 13. However, the rates generated by the MCS fail to meet the Department's goal of rate continuity and warrant adjustment on that ground. Exh. FGE-JLH-1 (Electric) at 022.

i. Response to the Attorney General

The Attorney General argues that the Electric Division MCS is flawed. AG Br. at 71. While Mr. Harrison readily admitted that there were difficulties in preparing the MCS for FG&E's Electric Division, those difficulties were not insurmountable, given Mr. Harrison's expertise and lengthy experience in this area. One of the areas exhibiting the greatest challenge to Mr. Harrison was the quantification of Transmission Investments. The Attorney General fails to mention that the marginal transmission costs are irrelevant to the design of delivery rates in this case. Moreover, the difficulties in creating the Electric Division MCS do not make it void from an evidentiary standpoint: the Department applies a "weight of the evidence" standard to all the evidence it reviews. Surely that premise will be in play here. Nevertheless, the MCS for the Electric Division was created by an expert in the field and is recommended by that individual (who is accepted by the Department as an expert) as useful for the purposes for which such a study is created.

The fact that Mr. Harrison employed his judgment should be expected: MCS studies inherently rely on expert judgment in a more direct manner than COS studies. There is no basis on the record to reject Mr. Harrison's Electric Division MCS merely because other judgments may have been applied. Since the Attorney General forwent presentation of an affirmative case relative to rate design or any other reasonable judgment that could be adopted, Mr. Harrison's recommendation is worthy of due consideration by the Department.

The Attorney General makes the claim that Mr. Harrison should have made use of some alternative escalation rate rather than a Handy-Whitman Index. AG Br. at 71. However, he provides no citation, so it stands without any weight whatsoever. He then describes that degree days are used to measure marginal plant investments. AG Br. at 71. Of course, the record shows the proper measuring stick is design day load. Exh. FGE-JLH-1 (Electric) at 033. The argument suggests, however, that the regression results should match actual investments over time. See AG Br. at 71. However, this is based on a false premise: The fact that MCS frequently differs from average historic costs is a major reason why we do MCS studies instead of relying on embedded cost studies alone. Once again, no citation is provided from the record or any other authoritative source.

Finally, the Attorney General asserts that because the MCS results differ from historic average cost, there is an inference that the MCS is unreliable. AG Br. at 71 (demonstrates "lack of concern for accuracy or consistency"). However, MCS is applied as an incremental, unitized, forward-looking assessment. As such, the MCS estimates may or may not resemble historic average costs. The existence of differences from past experience is never a reliable measure of the accuracy of the study. This accusation, therefore, has no place in any analysis of marginal costs.

2. Gas Division MCS

FG&E's Gas Division marginal cost estimate contains a marginal commodity cost component intended to reflect the short run variable cost of varying FG&E's level of gas sendout by one unit, assuming FG&E's production capacity is held constant. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6. The marginal distribution component is intended to reflect the unitized cost, based on historical data and recent trends, of expanding the local distribution network to accommodate growth in customers' requirements. Id. Mr. Harrison computed the marginal costs to serve each of FG&E's Gas Division rate classes based on rate year costs. Id.

To estimate the daily commodity cost of serving a small increment of customer load, NYMEX gas futures were used and adjusted for the cost at FG&E city gate. Exh. FGE-JLH-1 (Gas) at 032. To estimate production capacity costs, the peaker method was used. Exh. FGE-JLH-1 (Gas) at 032. Regression and engineering techniques were used to estimate hypothetical distribution costs, including the unit costs of adding distribution plant facilities as well as the added O&M. Exh. FGE-JLH-1 (Gas) at 032. To identify needed investment in services and meters, engineering estimates were used. Exh. FGE-JLH-1 (Gas) at 032. The annual revenue requirements to serve each rate class were developed, stating costs in terms of customer, commodity and demand charges. Exh. FGE-JLH-1 (Gas) at 032.

The MCS uses three time periods: (1) the design day; (2) the six winter months of November to April; and (3) the six summer months of May to October. Exh. FGE-JLH-1 (Gas) at 032-033. Design day was used to measure capacity costs because design day, a theoretical concept, is the primary planning criterion for FG&E's decisions concerning sizing of production and distribution capacity costs. Exh. FGE-JLH-1 (Gas) at 033. The summer season represents the period when both temperatures and sales and sendout are moderate; the winter season, when weather conditions are more severe and utility loads increase. Exh. FGE-JLH-1 (Gas) at 033.

In addition the MCS calculated demand or capacity costs. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 9. For gas distribution companies, these costs consist of production and distribution functions, to create the unitized cost of expanding production or distribution capability to meet a long-run increase in customers' requirements for gas service. Exh. FGE-JLH-1 (Gas) at 035. Under the peaker method, the least capital intensive capacity source that can be added to meet peaks of short duration is identified. Exh. FGE-JLH-1 (Gas) at 036. For FG&E, the expansion of an existing LP-air facility was the least costly available alternative to serve peak load growth. Exh. FGE-JLH-1 (Gas) at 036; Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 1. The modified peaker method computes the long-run marginal capacity costs, discounting the costs of pure capacity when current capability exceeds current requirements. Exh. FGE-JLH-1 (Gas) at 036.

The MCS derived distribution capacity costs by examining the long-run marginal costs of expanding the existing gas distribution system and the long-run marginal costs of adding main extensions. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 2.

Prospective Additions anticipates the unit cost of additional main extensions based on a 15-year, forward-looking analysis prepared to forecast reinforcement costs and the incremental cost per Dt for main extensions. Exh. FGE-JLH-1 (Gas) at 038. The total unit cost for prospective additions is the sum of these two unit costs. Exh. FGE-JLH-1 (Gas) at 038. Mr. Harrison evaluated two other estimates of distribution capacity cost to insure the reliability of his estimate. He computed the incremental cost of investments over the past 13 years adjusted to current Dollars using the Handy-Whitman Index for Public Utility Costs and divided it by the load growth over the same period. Finally, he performed a statistical regression that derives the unit cost per design day Dt by regressing the cumulative investment in new capacity-related distribution plant against the annual design day capability requirement. Exh. FGE-JLH-1 (Gas) at 038. Given these three approaches, Mr. Harrison adopts the Prospective Additions approach as the best estimate. Exh. FGE-JLH-1 (Gas) at 038. This same methodology was reviewed and accepted by the Department in other recent rate proceedings.

Capacity-related distribution O&M expense was determined by an account-by-account historical review, supplemented by Mr. Harrison's professional judgment. For instance, Account 874, Mains and Services Expense, had both a capacity and customer-related component, so the costs were segregated on relative plant investments in Mains and Services. Account 878, Account 879 – Customer Installation Expenses, Account 892 – Maintenance of Services, and Account 893 – Maintenance of Meter and House Regulator Equipment were directly assigned to the customer component. Exh. FGE-JLH-1 (Gas) at 039; Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas). In addition, Supervision and Engineering expenses in Accounts 850 and 885, were prorated to the customer and capacity components in proportion to all other distribution O&M expenses.

Annual capacity-related expenses were indexed to current year Dollars using the year-end GDP Implicit Price Deflator, to determine capacity-related O&M expenses in current dollars, and a time-series regression was employed. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 1. The time-series regression confirmed the declining average cost per Dt, confirming the engineering opinion that new materials were acting to lower O&M costs. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 5.

Marginal capacity costs were tabulated by production and distribution function. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 9.

For commodity costs, the study defined marginal commodity costs as the short run cost of serving a small increment in customer load in the winter or summer seasons. Exh. FGE-JLH-1 (Gas) at 040. Marginal commodity costs were estimated on NYMEX futures for the rate year, adjusted to reflect prices delivered to the Fitchburg city gate. Exh. FGE-JLH-1 (Gas) at 040. In order to produce load weighted marginal commodity costs, the monthly system incremental unit costs were load weighted by sales for each of the marginal cost study's classes in order to develop class by class, winter and summer marginal commodity costs. Exh. FGE-JLH-1 at Sch. JLH-6, Table 4, Table 8.

Marginal commodity costs are calculated on short-run gas costs, adding other variable production plant O&M expense and working capital requirements, and adjusting for seasonal use, losses, Company use and unaccounted-for gas. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 4, Table 7, Table 10.

Marginal customer costs, the long-run marginal costs of serving an additional customer, were computed in three categories, representing the costs of connecting and serving a customer for each of the proposed rate categories. Exh. FGE-JLH-1 (Gas) at 042. These costs are (1) plant investment in services and meters; (2) related operations and maintenance expenses; and, (3) billing costs such as customer accounting and customer information expenses. Customer-related plant investment for services was computed using average replacement costs new for each customer class and then factoring those costs by the services-per-customer ratio. Exh. FGE-JLH-1 (Gas) at 042; Exh. FGE-JLH-1 at Sch. JLH-6 (Gas), Table 3. Meter investment was developed from current costs, estimated installation costs and estimated regulator costs, and installed meter cost was factored by meters per customer ratios to recognize the need for spares. Id.

Customer-related distribution operations and maintenance expenses were restated in current dollars, using the GDP Implicit Price Deflator, and then evaluated against load growth. Next, the average annual cost was derived and was regressed against the time series. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 6. When the regression efforts yielded weak relationships, the recent 6 year average cost was deemed to be a reasonable estimate of marginal costs to serve a new customer. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 6.

Customer accounting expenses were determined without the benefit of strong statistical correlation. Exh. FGE-JLH-1 (Gas) at 043. A declining customer base has increased average cost slightly; therefore, the average cost per customer for the past five years was chosen as a proxy for the average marginal customer-related accounting costs. Id. Using the causal relationships identified in the COSS, marginal customer costs were computed for each customer class, excluding uncollectible expenses. Compare Exh. JLH-1 (Gas) at Sch. JLH-5-2 (Gas) and Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 6, p. 4. As Mr. Harrison explained, the uncollectible accounts expenses were imputed to each cost component using a write-off percentage for each class. Using this approach, production capacity and commodity costs, previously functionalized as gas supply-related, were grossed up to include an allowance for uncollectibles based on each class's write-off percentage. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 12.

Table 11 shows the development of marginal customer-related costs by class were developed by converting plant investments for customer-related costs to an annual expense, adding appropriate loaders and working capital requirements, and reflecting price escalation in the rate year. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 3, 6, 7, 11. Loading factors were used to compute estimates of marginal costs where direct quantification is either too complex or the costs are insignificant. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 7. A loss factor was also separately computed. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Tables 2, 10.

The fixed carrying charge was levelized and used to convert one-time investments into annualized revenue requirements, necessary for pricing. For rate-making purposes, utility investments in fixed plant are normally treated as rate base items. Utility rates are established periodically to allow the recovery of costs incurred in ownership, including such items as return, taxes, depreciation, etc. Rather than deal with an irregular set of annual costs stemming from ownership of assets, levelized fixed charge rates compute the present worth of all revenue requirements stemming from utility ownership of an asset, and then provide an equivalent annual payment stream of identical present worth. Exh. FGE-JLH-1 at 046-047.

The MCS is summarized by Mr. Harrison, tabulating the long-run marginal cost and revenues that would be generated if FG&E were to introduce full marginal cost-based pricing and if customers were to continue to consume as they have in the past. Exh. FGE-JLH-1 (Gas) at Sch. JLH-6 (Gas), Table 12. Unit costs are derived as well. Id. at Table 13. Mr. Harrison argued that if "marginal cost-based rates were not constrained to utility-allowed revenues and if economic efficiency were the only goal of rate design, these marginal cost figures could be considered marginal cost-based prices." Exh. FGE-JLH-1 (Gas) at 047. However, the results of the marginal cost study would not be implemented without careful attention to the Department's goals of rate continuity and efficiency.

i. Response to Attorney General

As with the marginal cost study presented for the Electric Division, the Attorney General believes the MCS presented for the Gas Division is also flawed, or at the minimum, carelessly paints his criticisms with the same broad brush. AG Br. at 71. However, unlike the Electric Division MCS, there is no record evidence of any difficulties in obtaining or interpreting the information available about the Gas Division marginal cost structure. Nor does the Attorney General assert that the record contains any. In point of fact, the same gas methods were used and approved by the Department for this Company previously. There is no record support behind any of the Attorney General's attempts to deride the Gas Division MCS.

D. Revenue Targets

1. Electric Division Revenue Targets

FG&E's proposed rate design includes the COSS results, shown at equalized rates of return for all classes, and the MCS results, for comparison purposes. Exh. FGE-JLH-1 (Electric) at 023; Exh. FGE-JLH-1 (Electric) at Sch. JLH-4. The delivery service revenue requirements from the MCS have been adjusted proportionately to match the delivery service revenue requirements from the COSS. Exh. FGE-JLH-1 (Electric) at 023. Customer class revenue targets are calculated by comparing present revenues with the revenues necessary if each customer class were charged with producing FG&E's requested return. Exh. FGE-JLH-1 (Electric) at 023. In order to avoid undue customer impact, class revenue requirements were capped at 125 percent of the overall average increase requested, consistent with Department precedent. Exh. FGE-JLH-1 (Electric) at 023; see also Berkshire Gas Co., D.T.E. 01-56 at 143. No customer class is to receive a decrease. Id. Preliminary revenue targets are initially generated by allocating any revenue moved because of the cap to the remaining classes on a pro rata basis. Exh. FGE-JLH-1 (Electric) at 024. Finally, the low-income discount is computed, allocating the subsidy back to all classes using a rate base allocator. Exh. FGE-JLH-1 (Electric) at 024. FG&E's Electric Division revenue targets result. Exh. FGE-JLH-1 (Electric) at Sch. JLH-4 (Electric).

2. Gas Division Revenue Targets

FG&E proposes to update indirect gas costs as part of its CGA. See Exh. FGE-JLH-1 (Gas) at Sch. JLH-7 (Gas). Direct and Indirect Gas Costs have been allocated and present revenues with and without gas costs are presented. The class revenue requirement is presented based on the COSS and the MCS results, with equalized rates of return for all classes. See Exh. FGE-JLH-1 (Gas) at Sch. JLH-7 (the MCS, adjusted equiproportionally, is provided for comparison).

In order to develop revenue targets, Mr. Harrison compared present base revenues and the COSS costs to serve at equalized rates of return, and determined that significant differences resulted, especially for residential non-heating. However, cost to serve would not be a reasonable basis upon which to set rates for this class because of potential for rate shock. Therefore, Mr. Harrison set revenue targets systematically, capping or limiting individual rate increases by class to 125% of the system average increase. Exh. FGE-JLH-1 (Gas) at Sch. JLH-7 (Gas), at 6. Gas costs were removed, and target base revenues calculated for the residential class prior to considering the low income rate discount (40%). Exh. FGE-JLH-1 (Gas) at Sch. JLH-7 (Gas). The low income subsidy was then allocated back to all classes using a rate base allocator to determine the proposed base revenue targets. Id. Gas costs were added to derive total revenue targets and the resulting overall increases. FG&E believes the resulting revenue targets are reasonable and promote efficiency and rate continuity.[35] See D.T.E. 5-4; Tr. 8/13/02 (Vol. 5) at 678-685.

E. Rate Design

FG&E's rate design was supported by Karen M. Asbury, who explained the proposed changes to FG&E's electric and gas distribution base rates, electric transition charge and gas production base rates, as well as the revised tariffs and bill impact analysis. Exh. FGE-KMA-1 at 348. The tariff revisions reflect the proposed changes to FG&E's electric and gas distribution rates and electric transition charges, proposed to take effect for usage consumed on and after June 1, 2002. Exh. FGE-KMA-1 (Electric) at 350. On the gas side, they also reflect proposed changes to certain production base rate components, the modification in the MBA methodology for the assignment of costs, and minor tariff language revisions. Exh. FGE-KMA-1 (Gas) at 359.

The Department's rate structure goals can be summarized as follows: the rate design and structure of a jurisdictional company must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. Berkshire Gas Co., D.T.E. 01-56, at 134-35 (2002).[36] The rate structure must communicate to consumers what the price of the product is, be cost-based, be easy to understand, and any changes should be gradual, so consumers can adjust utility consumption accordingly. No class of consumers should pay more than the costs to serve that class.

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35 Mr. Harrison tried to explain and distinguish his method he used of allocating uncollectibles as compared to Department practice. Tr. 8/13/02 (Vol. 5) at 559-571.

36 Additional citations include: Boston Gas Co., D.P.U. 96-50 (Phase 1), at 133 (1996); Boston Gas Co., D.P.U. 93-60, at 331-32 (1993); Berkshire Gas Co., D.P.U. 92-210, at 201 (1993); Cambridge Electric Light Co., D.P.U. 92-250, at 163 (1993); Massachusetts Electric Co., D.P.U. 92-78, at 116 (1992); Nantucket Electric Co., D.P.U. 91-106/138, at 110-111 (1991); Western Massachusetts Electric Co., D.P.U. 90-300, at 13-15 (1991); and Boston Edison Co., D.P.U. 1720, at 112-20 (1984).

Accordingly, rate structure is determined by (1) cost allocation and (2) rate design. Exh. FGE-KMA-1 (Electric) at 353; Exh. FGE-KMA-1 (Gas) at 361. Rate design also is important because it produces a set of prices intended to generate a certain level of revenue from each class. Id. This ensures the utility's ability to continue to service its customers.

1. Electric Division Rate Design

As part of its rate design, FG&E decided that it will no longer offer Optional Time-of-Use Rate RD-4 ("RD-4") and Optional Small General Delivery Time-of-Use Rate GD-6 ("GD-6"). Exh. FGE-KMA-1 (Electric) at 351. These services have little or no participation and are ineffective in shifting load. Exh. FGE-KMA-1 (Electric) at 351. According to Ms. Asbury, eliminating these two low participation rates advances the goal of simplicity and reduces the cost of rate administration and should be allowed. Exh. FGE-KMA-1 (Electric) at 351.

Massachusetts law requires rates by customer class to be limited to 85% of the inflation-adjusted rates in effect in August 1997. St.1997, ch. 164 ("the Act"). Additionally, rates for each customer class include a uniform Transition Charge ("TC") which must be equal across all classes. FG&E's uncollected transition charge balances currently accrue interest at the rate of 12.45% per year. Exh. FGE-KMA-1 (Electric) at 353.

FG&E's distribution base rates were redesigned to reflect 2001 test year costs and to mitigate customers' long term obligations for repayment of transition costs. Exh. FGE-KMA-1 (Electric) at 353-54. Energy and demand charges were set at marginal cost, and FG&E reconciled the target revenue expected for recovery through its customer charges. Exh. FGE-KMA-1 (Electric) at 354. FG&E then began the process of adjusting the rate components to determine transition charges in light of the Act's rate cap provisions. Exh. FGE-KMA-1 (Electric) at 355.

FG&E then considered current rates in light of the goal of rate continuity and restructuring limitations, reconciling target revenue on the remaining rate components, while ensuring the rate cap was not exceeded. Exh. FGE-KMA-1 (Electric) at 355.

FG&E's initial rate class increase guideline of 125% of the total average increase, subject to modifications to conform to the restructuring guidelines, balances the goals of fairness and continuity. Exh. FGE-KMA-1 (Electric) at 356. This is also an efficient rate design because the most inelastic part of the bill is set as close to marginal cost as possible. Exh. FGE-KMA-1 (Electric) at 356. FG&E achieves simplicity: the structure is easy for customers to understand and straightforward to administer because there are only three components: the customer charge, single block energy charge, and single block demand charge. Exh. FGE-KMA-1 (Electric) at 356. Large customers have a time of use energy charge. Exh. FGE-KMA-1 (Electric) at 356.

Eight rates were developed. Exh. FGE-KMA-1 at 356-57. Revenue targets had been set and COSS and MCS developed. For Residential RD-1, the revenue target was identified as $8,028,710. Exh. FGE-KMA-1 (Electric) at Sch. KMA-3 (Electric). The preliminary rate design was developed by setting the energy charge at marginal cost. Id. Remaining revenue was reconciled on the customer charge. Low-Income RD-2 rate components were initially set at 60% of the RD-1 customer and energy rates, providing a discount of 40% compared to RD-1 rates. Preliminary rates were adjusted by applying the total increase for the class to each rate component. Id. Then the UTC was set. Exh. FGE-KMA-1 (Electric) at Sch. KMA-4 (Electric). All rate schedules were calculated through this interim proposed rate design stage. Once this was accomplished, the initial transition charge for each customer class was determined based on the class-specific rate limitations imposed by restructuring. The total transition charge revenue was calculated and a UTC determined. As shown on Schedule KMA-4 (Electric), the UTC is

$0.01357 per kWh. This UTC rate replaced the initial calculated transition charge for each customer class. The revenue shift caused by this substitution required additional refinements to distribution rate components to arrive at the final customer charges and energy rates necessary to comply with the restructuring rate cap limitation. Exh. FGE-KMA-1 (Electric) at 358; Exh. FGE-KMA-1 (Electric) at Sch. KMA-5 (Electric).

For GD-1, the same process was used. After the UTC was optimized, the customer charge was increased to comply with the restructuring class rate cap and minimize individual customer impacts. Exh. FGE-KMA-1 (Electric) at Sch. KMA-3 (Electric). The same process was used for GD-2, GD-3, GD-4, and GD-5. Exh. FGE-KMA-1 (Electric) at 359; Exh. FGE-KMA-1 (Electric) at Sch. KMA-2 (Electric). However, FG&E proposes to move the customer charge toward the marginal cost for these customers. Exh. FGE-KMA-1 (Electric) at Sch. KMA-2 (Electric). The remaining revenue was then reconciled on the energy component and demand components. Id. FG&E was vigilant about ensuring that individual customer bill impacts were as close as possible to the 15% rate reduction. Exh. FGE-KMA-1 (Electric) at Sch. KMA-7 (Electric).

With regard to street-lighting, FG&E established that rate design by first, identifying the revenue target. Exh. FGE-KMA-1 (Electric) at 361; Exh. FGE-KMA-1 (Electric) at Sch. KMA-3 (Electric). Next, current rates were adjusted by applying the total increase for the class to each rate component. Exh. FGE-KMA-1 (Electric) at 361. As done for all other classes, the revenue shift caused by substituting the UTC for the class transition charge required additional refinements to distribution rate components to arrive at the final customer charges and energy rates necessary to comply with the restructuring rate cap limitation. Exh. FGE-KMA-1 (Electric) at 361. FG&E performed these refinements by adjusting the luminaire charge and energy charges by an equal percentage to meet the adjusted revenue target. Exh. FGE-KMA-1 (Electric) at 361-62. Exh. FGE-KMA-1 (Electric) at Sch-KMA-5 (Electric) - provides the compliance calculation for Rate SD - Outdoor Lighting.

Sch. KMA-6 (Electric) provides a calculation of the accuracy of the test year billing determinants for demand and energy. In order to obtain an accurate count of bills for use in rate design, FG&E divided customer charge revenues by the customer charge. Exh. FGE-KMA-1 (Electric) at Sch. KMA-5 (Electric). FG&E did the same for luminaire charges to determine number of lights. Exh. FGE-KMA-1 (Electric) at Sch. KMA-5.

The bill impacts demonstrate how the proposed rates compare to inflation adjusted August 1997 levels. Exh. FGE-KMA-1 (Electric) at Sch. KMA-7 (Electric); Exh. FGE-KMA-1 (Electric) at Sch. KMA-8 (Electric) (bill impacts of the proposed rates versus current rates for all customer classes). These impacts demonstrate the reasonableness of the proposed rate design.

2. Gas Division Rate Design

The model developed by Mr. Harrison identifies costs by functions such as production, commodity, etc. Allocations to the class and function dimensions are performed automatically. Exh. FGE-JLH-1 (Gas) at Sch. JLH-5 (Gas). Mr. Harrison also prepared an unbundled cost of service study for principle areas of cost recovery. Exh. FGE-JLH-1 (Gas) at 050; Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-3 (Gas) (including Production LPG, Production LNG, Production Demand, Distribution Pressure Support, Distribution-Other, Commodity Gas Cost, Customer Services, Customer Meters, Customer Deposits, Customer Late Payments, Customer Meter Reading, Customer Records, Customer Information); Exh. FGE-JLH-1 (Gas) at Sch. JLH-5-4 (Gas).

As Ms. Asbury describes, the rate design had to accommodate the revenue targets and capped increases of 125% of the total average increase, in order for rates to be fair and stable. Exh. FGE-KMA-1 (Gas) at 363.

For its residential non-heating rates R-1 and R-2, the target revenue was identified at $690,512. Id. Then marginal distribution costs were identified and summarized. The preliminary rate design for R-1 set the volumetric charge to marginal cost. Id. The remaining revenue was reconciled on the customer charge. Id. The R-2 rate component was similar, except they were set at 60% of R-1, in order to maintain the low-income rate discount applicable under law. Id. FG&E arrived at a final customer charge of $8.50 for R-1 recognizing both rate efficiency and rate continuity. The increase in the customer charge is approximately the same as the overall increase in the revenue requirement for the class. The volumetric charge was set so the total rates produce the revenue target. With regard to residential heating rates R-3 and R-4, the same process was used. Exh. FGE-KMA-1 at Sch. KMA-3. For FG&E's small and medium size general service customers, essentially the same process was used. The preliminary customer charges for G-41 and G-51 were $76.80 and $78.54, respectively. The final customer charge was set at $24.00 in order to maintain rate continuity for these customers. Id., at p 365-66. The preliminary customer charges for G-42 and G-52 were $447.41 and $413.71, respectively. The final customer charge for both classes was set at $120.00, again, recognizing rate continuity and rate efficiency.

For large general service customers (G-43 and G-53), final customer charge was set at $620, which was deemed essentially full marginal cost. Exh. FGE-KMA-1 (Gas) at 367. Because these customers have demand charges, FG&E reconciled the remaining revenue requirement half to demand, half to volumetric charges. This was consistent with Department precedent. D.T.E. 98-51 at 148. FG&E supports these results with a test for accuracy based on test year billing determinants. Exh. FGE-KMA-1 (Gas) at Sch. KMA-4 (Gas). The resulting differences were de minimis, and therefore, no adjustment was made to billing determinants thereafter. Exh. FGE-KMA-1 (Gas) at 367.

FG&E also revised its CGAC tariff to reflect FG&E's proposed rates for recovery of local gas costs and changes to the recovery mechanism. Exh. FGE-KMA-1 (Gas) at 367-68. Local gas costs were defined as (1) local production capacity and storage costs ("LPLNG"), (2) dispatch, acquisition and FERC proceedings cost ("DAFP"), and (3) production related overhead ("PRO"). Id. For consistency with FG&E's PBR filing, FG&E proposes in this proceeding that the existing reconciling features of these three rates be removed. In the PBR filing, FG&E proposes to adjust these rate components annually over the term of the PBR plan by a factor that reflects price inflation reduced by an enhanced productivity offset. By removing the reconciling features, these rates will operate like distribution rates.

FG&E recommends that its CGAC be permitted to recover the bad debt expenses associated with gas supply cost, but that since bad debt costs in the CGAC are reconciling, there is no need to propose a revised factor at this time. Exh. FGE-KMA-1 (Gas) at 370. FG&E proposed a change in how bad debt is recorded in the CGAC as discussed herein. Finally, FG&E requests that the Department implement the MBA method, discussed above, as part of its CGAC mechanism. Exh. FGE-KMA-1 (Gas) at 370. FG&E proposes to begin employing the new method on the date the revised distribution rates take effect. Id. In addition, Ms. Asbury noted that the CGAC would reflect the new cash working capital allowance pursuant to the Purchased Gas Lead/Lag Study provided in this docket, of 32.43 days. Id., at 371.

In her analysis of the resulting bill impacts of these changes, comparing the test year rates to the proposed rates and adding the CGAC impact, Ms. Asbury concluded the rates as designed were appropriate for implementation. See Exh. FGE-KMA-1 (Gas) at 371, Sch. KMA-6 (Gas).

3. Response to Attorney General

a. Tariffs Detailing Rate Formulae

The Attorney General claims that FG&E's tariffs are deficient, and recommends that the Department require FG&E to provide a set of clear and comprehensive definitions. AG Br. at 72. In addition, the Attorney General seems to indicate that detailed formulae including the MBA should be added to the Company's CGA tariff and its Terms and Conditions. Id. In light of this concern, FG&E has reviewed its tariff. It continues to believe that the tariff, as a rate contract between customers and the Company, should be clear and concise and to the point, as it already is. It provides the term of service, the nature of service, the responsibilities of the parties, the price terms and other reasonable and useful information in complete conformance with the Department's requirements. 220 C.M.R. 5.00 et seq. For other information regarding the niceties of rate design, the public is free to visit the Internet, call the Department, call the Attorney General, or call the Company. The Attorney General's suggestion will burden and confuse an already complicated document for most customers.[37]

Furthermore, contrary to the Attorney General's assertion, the Company does not have the ability to "slip through" what may be a significant rate change in a CGAC proceeding. The Company's CGAC filing provides sufficient narrative and calculations, and in particular documents methodologies that were approved in a previous rate case. The Company's compliance filing in this proceeding, which is subject to review and approval of the Department,

[37] The suggestion is akin to recommending that a COSS be attached to each tariff.

will naturally set forth a model for future CGAC filings. The Company's tariffs should be approved as filed, reflecting any rate adjustments the Department in its discretion should order.

b. PBR Inflation Factor

Although FG&E made a motion to consolidate these rate proceedings with its PBR proposal, the Department decided not to act on the motion at any critical stage in the proceeding. Now, on brief, the Attorney General argues that FG&E's proposal to apply an inflation factor to its production costs under its PBR should be rejected. AG Br. at 74-76. The Attorney General's request is both untimely and contrary to current Department policy. Historically these costs have reconciled through the CGA; now unbundled, there is no reason to believe they will decline. Rather, FG&E's expectation is that this group of costs will rise. In addition, these are new base rate costs and reconciling is inconsistent with base rate costs; therefore, the application of an inflation factor is more appropriate to match incentives with risks.

This issue is not before the Department on this record, and the Attorney General has cited no authority for his position. The Attorney General's complaint about FG&E's PBR mechanism should be rejected. The issue before the Department in this proceeding is whether or not the reconciling features of the production base rate components (LPLNG, DAFP, and PRO) should be removed. Since these cost were historically part of base rates, the same ratemaking treatment should be afforded. Accordingly, the Attorney General's complaint about FG&E's PBR mechanism should be rejected and the Company's proposal to remove the reconciling features should be approved.

F. DOER's Proposal For Increased Customer Charges

DOER recommends that FG&E's customer charges be increased. DOER Br. at 15. FG&E agrees that accompanied by a detailed analysis, this policy decision would recognize and reach other goals of rate design: rate continuity, efficiency, fairness, and intergenerational equity. While FG&E has not conducted analytical analysis or investigated DOER's position, it believes it has merits, and would not object, should the Department review the DOER's position and be persuaded by it.

VII. RETURN ON EQUITY FOR THE ELECTRIC AND GAS DIVISIONS

A. Introduction

In support of the recommended gas and electric return on equity ("ROE"), FG&E presented the analysis of expert witness, Dr. Samuel C. Hadaway. Exh. FGE-SCH-1 (Electric); Exh. FGE-SCH-1 (Gas). Dr. Hadaway is a principal and founder of FINANCO, Inc., Financial Analysis Consultants and an adjunct professor in the Graduate School of Business at the University of Texas at Austin. Id. at 003 (Gas and Electric). He received an economics degree from Southern Methodist University, and an MBA and Ph.D. degrees in finance from the University of Texas at Austin. Dr. Hadaway was previously Director of the Economic Research Division of the Public Utility Commission of Texas, where he supervised the Commission's finance, economics, and accounting staff and served as the Commission's chief financial witness in electric and telephone rate cases. Id. He has taught courses in utility cost of capital, capital structure, utility financial condition, and cost allocation and rate design issues. Dr. Hadaway has made presentations to numerous professional and legislative groups, and has been a vice president and board member of the Financial Management Association. A list of his numerous publications and testimony before regulatory bodies and state and federal courts is contained in Appendix A to his gas and electric prefiled testimony. No party has challenged Dr. Hadaway's credentials as an expert.

It is well established that a utility is entitled to a return on common equity that is sufficient to preserve the utility's financial integrity, that enables the utility to attract capital on favorable terms, and that permits the utility to realize earnings on a par with investments of comparable risk. See Bluefield Water Works and Improvements Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1942); see also Fitchburg Gas and Elec. Light Co., D.T.E. 99-118 at 78 (2001). FG&E's proposed rate of return of equity ("ROE") of 11.5% reflected in FG&E's electric and gas rates in this docket is consistent with this standard.

B. FG&E's Proposed Return on Equity is Fair and Reasonable

Dr. Hadaway has employed the approach that the Department has consistently endorsed, i.e., a combination of the discounted cash flow ("DCF") and risk premium models. Id. at 005. See Fitchburg Gas and Electric Light Company, D.T.E. 99-118 (Oct. 18, 2001); Berkshire Gas Company, D.T.E. 01-56 (Jan. 31, 2001). In response to the Department's concerns in FG&E 's last rate case, D.T.E. 99-118, in his testimony and analyses in these cases, Dr. Hadaway implemented several modifications. Tr. 8/22/02 (Vol. 10) at 1129-1133. For example, he changed the composition of the comparison group in the electric DCF analysis and substituted a new two-stage growth model for the "Competition DCF" model used in the last case. Id.

For the Electric Division, Dr. Hadaway's DCF analysis indicates that an ROE range of 10.5% - 12.6% is appropriate, and the risk premium analysis indicates a ROE of 12.0% is appropriate. Exh. FGE-SCH-1 at 005 (Electric). For the Gas Division, the DCF analysis supports an ROE range of 11.4% - 12.5%, and Dr. Hadaway's risk premium analyses indicates that an ROE of 11.9% is appropriate. Exh. FGE-SCH-1 at 005 (Gas).

Based upon these quantitative results, and the witness' review of the current market, industry, and company-specific factors, Dr. Hadaway concluded that the just cost of equity for both FG&E's Electric and Gas Divisions is 11.5%. Id.

1. <u>Estimating the Cost of Equity Capital</u>

The cost of equity capital is the profit or rate of return that equity investors expect to receive. Exh. FGE-SCH-1 at 006 (Electric and Gas). In the DCF format, the cost of equity is measured by calculating the expected dividend yield as a percentage of the stock's price, and adding that to the expected growth. <u>Id.</u> The sum of these two returns is the appropriate measure of the cost of equity capital because it is this rate of return that caused the investor to commit the capital in the first place. <u>Id.</u> at 007. Because the market acts quickly and continuously in reflecting investors' expectations, the prices of the utility's stock generally reflect investor expectations as to the level of return necessary to undertake the level of risk of the investment relative to comparable investments. <u>Id.</u> Therefore, in accordance with <u>Bluefield</u> and <u>Hope</u>, <u>supra</u>, the fair rate of return should closely parallel investor opportunity costs. <u>Id.</u> at 11. If a utility earns its market cost of equity, neither its stockholders nor its customers should be disadvantaged. <u>Id.</u>

2. <u>Dr. Hadaway Used the Two Methods for Estimating the Cost of Equity That Are Widely Used in Regulatory Practice.</u>

Techniques for estimating the cost of equity normally fall into three groups: (1) comparable earnings methods; (2) risk premium methods; and (3) DCF methods. <u>Id.</u> at 11. The original comparable earnings methods were based upon book accounting returns for unregulated companies that have risks similar to the regulated company in question. <u>Id.</u> at 12. However, these methods generally have been rejected because they assume, incorrectly in most cases, that the unregulated companies are earning their actual cost of capital, and that their equity book values are the same as their market book values. <u>Id.</u> Also, differences in accounting methods between companies and issues of comparability detract from this approach. <u>Id.</u> More recent comparable earnings methods are based on historical stock market returns rather than book accounting returns. However, this newer approach has also been criticized because there is no assurance that historical returns actually reflect current or future market requirements, and because earned market returns tend to fluctuate widely from year to year. Consequently, a current cost of equity estimate based on the DCF model or a risk premium analysis is usually required. Id.

The second type of estimation techniques, risk premium methods, use currently observable market returns (i.e., yields on bonds) and add an increment to account for the additional equity risk. Id. Risk premium methods are based on the assumption that equity securities are riskier than debt and, therefore, investors in equity securities require a higher rate of return. Id. at 17. This assumption is well-supported by legal distinctions between debt and equity securities and is widely accepted as a fundamental principle underlying the capital market. Id. More sophisticated risk premium approaches, such as the capital asset pricing model ("CAPM") and arbitrage pricing theory ("APT") model combine the relatively risk-free government bond rate with explicit risk measures to determine the risk premium required by the market. Id. at 13. These methods are not widely used in most regulatory jurisdictions, however, because of their additional data requirements and their potentially questionable underlying assumptions. Id. Instead, the basic risk premium method is useful as a parallel approach to the DCF model and assures consistency with other capital market data. Id. at 13. Although there is some debate about whether to use very long or very short periods of analysis, the important question that the analysis should address is the rate of return that equity investors reasonably expect relative to returns that are currently available from long-term bonds. Id. at 18-19. Dr. Hadaway's recommendation is based on an intermediate time-frame that avoids many of the problems associated with very long or very short periods of analysis. Id. at 19.

The third type of estimation techniques, based on the DCF model, is the most widely used regulatory cost of equity estimation method. Id. at 13. The DCF model is predicated on the concept that stock prices represent the present value or discounted value of all future dividends that investors expect to receive. Id. at 14. The DCF method adds the expected dividend yield and the expected long-term dividend (or price) growth rate. Id. at 15. The DCF method has been criticized as too speculative due to the estimation of long-term growth, resulting in the preference for the multistage growth DCF analysis. Id.

The basic model uses a present value calculation based on the assumption that the stock's price is the present value of all dividends expected to be paid in the future. Id. Under the additional assumption that dividends are expected to grow at a constant rate, which will always be less than investors' required rate of return on equity, the basic model can be solved as to the ROE and rearranged into a simple equation called the constant growth DCF model. Id. at 14. However, when growth rates are expected to fluctuate or when future growth rates are highly uncertain, the non-constant growth form of the model should be used over a finite transition period during which uncertainty prevails and then the constant growth version of the model can be applied after the transition period under the assumption that more stable conditions will prevail in the future. Id. at 15.

Alternatively, one of two variations on the basic model can be used, which account for a finite period of non-constant growth, followed by constant growth, i.e., (1) the "Market Price" version, and (2) the "Multistage" or two-stage growth approach. Id. at 15-16. The nonconstant growth models are based on the same valid capital market assumptions as the constant growth version, but require explicit data inputs that are available from investment and economic forecasting services. Id. at 16. He also conducted a risk premium analysis to corroborate the results of his three DCF analyses.

The DCF and risk premium methods have become the most widely accepted in regulatory practice, replacing the oldest but perhaps most unreliable method, the comparable earnings method. Id. at 019. A combination of the DCF model and risk premium data provides the most reliable estimate of the cost of equity, as the data inputs are readily obtainable and the model's results are generally consistent with actual capital market behavior. Id.

3. Market Factors Affect the Cost of Equity

Over the past ten years, inflation and capital market costs have been relatively stable and lower than prevailed in the 1980s. Id. at 020; Exh. FGE-SCH-1. Estimates for 2002 indicate improved economic growth with continual price stability and moderately higher interest rates. Id. at 20 (Gas), 21 (Electric). Abroad, increasing uncertainty, and, at times, extreme capital market volatility have contributed to changing costs of capital relationships. Id. More recently, unusual supply and demand conditions for U.S. treasury bonds have caused other market anomalies, with the government rate declining more rapidly than rates on other securities. The decreasing average rates for utility bond yields for the three months ending March 2002 were used as the current cost of debt rate in Dr. Hadaway's risk premium analysis. Id. at For the most recent three months prior to Dr. Hadaway's testimony, Moody's Baa (triple B) Utility Rate was 8.22%, and the S&Ps BBB Electric Utility Rate was 8.32%. Id. at Exh.-FGE-SCH-1, Sch. SCH-2 (Gas), and Exh.-FGE-SCH-1, Sch.-SCH-3 (Electric).

Stock prices for many utility companies have fluctuated widely during the past two years. Id. at 21 (Gas), 22 (Electric). Currently, the greatest concern among utility investors is the continuing movement toward competition and the uncertainty caused by unbundling and general restructuring of both the gas and the electric industries. Id. Utility investors are obviously still reacting to the California energy crisis, and the cascading affects on other Western utilities as well as by the collapse of Enron. Exh. FGE-SCH-1 at 23 (Electric). The Western energy crisis has refocused market concerns and has contributed significantly to increased market risk perceptions for the electric industry. Id. at 024. As expected, the opening of previously protected utility markets to competition, and the uncertainty created by the removal of regulatory protection, have raised the level of uncertainty about investment returns across the entire electric industry. Exh. FGE-SCH-1 at 024 (Electric).

Based on FG&E's Restructuring Plan in Massachusetts, customers have the ability to choose an energy supplier or to opt for standard offer service. As the provider of last resort, FG&E bears the risk of non-payment or for the failure of energy service providers. Id. In Massachusetts, the transition to retail competition has been very slow to develop. Id. Although the Department has approved FG&E's recovery of stranded assets, over the next decade, to the extent there are unexpected changes in political, regulatory and/or business environments, FG&E's recovery of these stranded assets may be affected, creating business risk and uncertainty. Id. at 024-025 (Electric).

On the gas side of the business, as a result of FERC restructuring initiatives, the operating environment for local distribution companies ("LDC's") such as FG&E has been more complex and competitive which translates to increased risk. Exh. FGE-SCH-1 at 022 (Gas). In addition to the continuing affects of industry unbundling and restructuring, FG&E faces direct competition from alternate energy sources, such as oil and propane. Id. LDC's have also experienced the negative affects of a slowing economy, and warmer than normal weather. Id. Based upon these factors, Value Line has stated:

> The current operating environment remains unfavorable for gas utilities . . .. This industry remains in the bottom tier of the Value Line universe for performance in the year ahead.

Value Line Investment Survey, March 22, 2002 at 461.

When risk perceptions increase or financial prospects decline, the market price for a company's securities declines, which typically translates to a higher cost of capital through a higher dividend yield requirement and the potential for increased capital gains if prospects improve. Exh. FGE-SCH-1 at 24 (Gas), 25-26 (Electric). The high cost of capital results in the company needing to issue more shares to raise capital for future investment, and the additional shares impose additional future dividend requirements and reduce future earnings per share growth prospects. Id. at 24 (Gas), 26 (Electric).

a. DCF Analysis Was Based on Accurate Comparable Groups and Appropriate Factors

Dr. Hadaway applied the DCF model to a comparable company group of gas distribution utilities, and to a group of Triple B, or higher-rated, electric utility companies. Exh. FGE-SCH-1 at 26 (Gas) and 28 (Electric). On the gas side, Dr. Hadaway did not individually select the comparison companies, but rather used the selection compiled by Value Line, the most widely subscribed and read source of information for the stock market value of gas distribution companies. The group includes gas distribution utilities covered in Value Line for which complete and reliable data was available, and for which domestic utility revenues account for 70% or more of total revenues. Id. For the Electric Division, Dr. Hadaway also used Value Line. The electric group also included only those electric utilities that derived at least 70% of their revenues from domestic utility operations. Id. at 28. The results of Dr. Hadaway's DCF analyses for the Gas Division indicate a range of 11.4% - 12.5%. Exh. FGE-SCH-1 at Sch. SCH-

4 (Gas) p. 1 of 5. The Electric Division DCF analyses support a range of 10.5% - 12.6%. Exh. FGE-SCH-1 at Sch. SCH-4 (Electric) p. 1 of 5.

The average stock prices from the most recent three months (January - March 2002) were used for each company, to ensure that the price is representative of current market conditions and not unduly influenced by unusual or special circumstances. Exh. FGE-SCH 1 at 27 (Gas) and 29 (Electric). To ensure that the stock prices were not skewed by unrepresentative initial prices, Dr. Hadaway calculated the average of high and low prices for each of the three months ending March 2002 for each company and compared that to Value Line's single month prices. Id. at 27 (Gas) and 29 (Electric). The difference was only 70 cents in the gas analysis, and 23 cents for the electric side, demonstrating that either three-month average stock prices or single month prices can be used in the DCF analysis without significantly impacting the results.

The Attorney General makes essentially the same argument he made and lost in D.T.E. 99-118, i.e., that Dr. Hadaway's comparison group is inappropriate because their investment risk is much greater than that of FG&E. AG Br. at 48-49. The Attorney General ignores the fact that the Department accepted a similar comparison group in D.T.E. 99-118 and found that Dr. Hadaway "applied a reasonable set of criteria in selecting the comparison group." D.T.E. 99-118 at 80. As Dr. Hadaway explained in detail at the hearings, he carefully reviewed the operating and regulatory characteristics of the companies he used in both his gas and electric analyses to ensure that they were appropriate. Tr. 8/22/02 (Vol. 10) at 1156-1159, 1177-78 and 1180.

Notwithstanding the Department's endorsement of his methodology in the last case, Dr. Hadaway took steps to further refine the comparison groups in this case to address concerns that some of the selected companies may be more risky than FG&E. Tr. 8/22/02 (Vol. 10) at 1129. Accordingly, on the electric side, Dr. Hadaway eliminated all companies in Value Line's west edition, i.e., the California and other western electric utilities that may have been affected by the energy crisis. Tr. 8/22/02 (Vol. 10) at 1180. In the gas sample, he restricted the companies included to ensure that at least seventy percent of the revenues of the group came from regulated activities. Id. at 1138. Thus, the Attorney General's criticisms of Dr. Hadaway's comparison group are without merit and should be rejected.

The Attorney General's suggestion that the comparison groups are unreliable because Dr. Hadaway "could not even identify the business for which the Department was setting rates in these cases" is entirely without merit. AG Br. At 52. Suffice it to say that the record shows Dr. Hadaway based his recommendation for the electric ROE on his analysis of the electric utility comparison group and his gas ROE on the gas utility comparison group. The fact that Dr. Hadaway had not memorized the Department's docket numbers for the gas and electric rate cases in these proceedings does not reflect upon the competency or reliability of his opinions and his analysis. Tr. 8/22/02 (Vol. 10) at 44-45.

Dr. Hadaway conducted three alternative approaches to the DCF model, the results of which are summarized in Exh. FGE-SCH-1 at Sch. SCH-4, attached to both Dr. Hadaway's gas and electric testimonies. In each model, the dividend yield was calculated by dividing Value Line's projected dividends for the coming year by the average price for each company for the three months ending March 2002. Sch. SCH-4 at 2 of 5.

(1) Constant Growth Rate Model

The constant growth analysis is modeled in the following equation:

$k = D1/Po + g$

where,

k = the discount rate, or the investor's required rate of return on equity

D1/Po is the expected dividend yield

g = the long-term expected dividend growth rate

FGE-SCH-1 at 14. The growth rates are an average of estimates taken from Zack's, Value Line, and the internal growth "br" method. Exh. FGE-SCH-4 at 2. The "br" method estimates growth by multiplying a company's earnings retention rate by its earned rate of return on equity. Id. The constant growth DCF analysis indicates an ROE range for the Gas Division of 11.9% - 14%, based on the group's average dividend yield of 4.78% plus an average growth rate of 6.38%. For the Electric Division, the constant growth analysis yields an ROE range of 10.8% - 11.1%, based upon the groups average dividend yield of 5.14% plus an average growth rate of 6.15%.

i. "Market Price"

The "Market" price nonconstant growth approach equation is:

$$Po = D1/(1+k) + D2/(1+k)2 + ... + PT/(1+k)T$$

Exh. FGE-SCH-1 at 16 (Electric) and 15 (Gas).

The variables are the same as for the basic DCF model, except that PT is the estimated stock price at the end of the transition period T. Id. at 015 (Gas) and 016 (Electric). Under the assumption that normal growth resumes after the transition period, the price PT is then expected to be based on constant growth assumptions. Id. In the above equation, the estimated cost of equity, k, is the rate of return that investors would expect to earn if they bought the stock at today's market price, held it and received dividends thought the transition period and then sold it for price PT. Id. The purpose of this approach is to estimate the rate of return that investors expect to receive given the current level of market prices they are willing to pay. The "market price" DCF model indicates a range of 12.2% - 12.59% for the ROE for the Gas Division, and a range of 12.4% - 12% for the Electric Division. Exh. FGE-SCH-1, Sch.-SCH-4 (Gas) at 3 of 5, Sch.-SCH-4 (Electric) at 3 of 5.

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Dr. Hadaway modified the "Market Price" model in these proceedings in order to address the Department's concerns in FG&E's last late rate case. See D.T.E. 99-118 at 83-84. In that case, Dr. Hadaway used a current price-to-earnings ("P/E") ratio in the market, but for the estimated future price, he used a future earnings per share number with the current P/E. The Department found that Dr. Hadaway's assumption that P/E ratios would remain constant was "tenuous at best" and for that reason placed limited weight on the Market DCF analysis. Id. at 84. In the current case, therefore, Dr. Hadaway used a P/E approach derived from Value Line to eliminate the Department's concern. Tr. 8/22/02 (Vol. 10) at 11131-32.

ii. "Multistage" Nonconstant Growth Approach

This approach expands the basic DCF model to incorporate two or more growth rate periods, with the assumption that a permanent constant growth rate can be estimated for some point in the future:

$$Po = Do(1+g1)/(1+k) + ... + Do(1+g2)n/(1+k)n+...+Do(1+gT)(T+1)/(k-gT)$$

where the variables are the same as in the basic model but g1 represents to growth rate for the first period, g2 for the second period, and gT for the period from year T (the end of the transition period) to infinity. Exh. FGE-SCH-1 at 16 (Gas) at 17 (Electric). The first two growth rates are estimates for fluctuating growth over "n" years (usually 5-10 years) and gT is a constant growth rate assumed to go into infinity after year T. Id.

This two-stage growth approach is entirely new and was included in this case to provide a more conservative alternative to Dr. Hadaway's "transition to competition model" which the Department criticized in the last proceeding. See D.T.E. 99-118 at 85, Tr. 8/22/02 (Vol. 10) at 1130. The two-stage growth DCF model indicates an ROE of 11.4% is appropriate for the Gas Division, and an ROE range of 10.5%-10.6% is appropriate for the Electric Division. This analysis is the most conservative and produced the lowest ROE estimates of the three methods because it used a lower growth rate than current analysts' growth rate estimates. Tr. 8/22/02 (Vol. 10) at 1130.

b. The Attorney General's Criticisms of the DCF Analysis are Not Credible

The Attorney General's technical criticisms of Dr. Hadaway's DCF analysis are erroneous. AG Br. at 54-55. His statements that Dr. Hadaway's growth estimates in the constant growth DCF model are "too high" are not supported by any expert opinion and are based on the Attorney General's mechanical extraction from historical data. As Dr. Hadaway explained, this approach is entirely inappropriate. Tr. 8/20/02 (Vol. 10) at 1191-1194. With dividend yields of about 5%, the Attorney General's advocacy of growth in the 1.8% - 2.6% would result in DCF estimates of ROE below the cost of debt (5% + 1.8% = 6.8% and 5% + 2.6% = 7.6%). See AG Br. at 55. Such results are not consistent with reasonable capital market theory and were specifically refuted by Dr. Hadaway. Tr. 8/22/02 (Vol. 10) at 1192. Similarly, the Attorney General's further mechanical extractions of growth data, including his estimate of future economic growth at 5.25% without any record support of appropriateness or support from any expert, cannot be the basis for a credible ROE estimate. See AG Br. at 56. The Attorney General conveniently adds his 5.25% growth expectation for the economy to Dr. Hadaway's electric comparison group dividend yield to obtain an ROE of 10.39% for the upper end on his range (5.14% dividend yield + 5.25% growth = 10.39% ROE). Dr. Hadaway specifically refuted the use of a 5.5% growth rate in combination with his dividend yield as an appropriate ROE estimate and the Attorney General offered no expert testimony to support such an approach. Tr. 8/22/02 (Vol. 10) at 1194.

The Attorney General's continuation of his growth rate extraction approach is similarly erroneous in his criticisms of Dr. Hadaway's multi-stage growth DCF analysis. AG Br. at 56-58.

The Attorney General offers unsupported, mechanically extracted data on Gross Domestic Product ("GDP") based on recent, historically low inflation rates that entirely skews his analysis. He offers no support for this approach or for the data he employs, other than a cite to D.T.E. 99-118 Order at 74, which at that time noted an historical GDP growth rate of 5.57%, over an eleven year period with the lowest inflation since the 1960's. If the Department should use this growth rate with the 5.14% dividend yield cited by the Attorney General above, the resulting ROE would be 10.71% (5.14% dividend yield + 5.57% growth = 10.71% ROE). It is no more appropriate for the Attorney General to select the lowest inflation period to estimate long-term growth than it would be for FG&E to base growth expectations on the late 1970's, when inflation and nominal GDP growth were at times almost twice as high as the 1990's period cited by the Attorney General. As Dr. Hadaway explained, a more balanced approach would find growth in the 6.5% range, and with a 5.14% dividend yield; such growth implies a DCF estimate of over 11.5% (5.14% dividend yield + 6.5% growth = 11.64% ROE). Tr. 8/22/02 (Vol. 10) at 1194. Contrary to the Attorney General's data extraction approach, Dr. Hadaway explained and supported his application of alternative DCF approaches and offered the Department a soundly reasoned, conservative estimate of ROE for both the Electric and Gas Divisions at 11.5%.

c. Risk Premium Analysis

The Department has endorsed the usefulness of Dr. Hadaway's risk premium analysis as "a supplemental approach to other ROE models, thereby ensuring consistency with other capital market data in the Department's investigation of the appropriate ROE." D.T.E. 98-118 at 85 (2000). Dr. Hadaway's gas risk premium analysis compared the average authorized ROE's to contemporaneous long-term interest rates on utility bonds. Exh. FGE-SCH-1 at 028 (Gas). The equity risk premium is then measured by the difference between the average authorized ROE and the average debt cost for each year. Id.; Exh. FGE-SCH-1, Sch. SCH-5, page 1. The resulting risk premium of adding 3.71% of to recent triple-B utility debt cost of 8.22% to arrive at the indicated ROE of 11.9 percent. Id. at 29. His risk premium studies indicate much lower risk premiums than found in many published studies, including the most widely followed risk premium studies: the Ibbotson Risk Premium and the Harris-Marston Risk Premium Analyses. These two analyses would indicate a cost of equity of over 13.12% and of 13.35%, respectively. Id. at 30 (Gas).

For the Electric Division risk premium analysis, Dr. Hadaway compared average ROE's allowed each year by the various state regulatory agencies to utility debt costs. Following the same process as the gas analysis, Dr. Hadaway's risk premium analysis indicates that an ROE of 12.0% is appropriate for FG&E's Electric Division.

In D.T.E. 99-118 the Department expressed concerns about Moody's bond indices in the interest rate part of the analysis because the indices include electric, gas and telephone interest rates. To address this concern, Dr. Hadaway used electric-only data based upon Standard Poor's, and did a separate risk premium analysis. See Exh. SCH-Sch-6 (Electric). Comparing the Moody's analysis in Schedule 5 to the new electric-only analysis in Schedule 6 reveals a negligible difference of 5 basis points. Although the Schedule 6 analysis was a useful check of reasonableness, the resulting electric ROE was exactly the same as in Schedule 5. Tr. 8/22/02 (Vol 10) at 1132-1133.

d. The Attorney General's "CAPM"

The Attorney General extends his personal "ROE analysis" even further by attempting to interject a Capital Asset Pricing Model (CAPM) approach as an ROE estimate. AG Br. at 62-64. The Attorney General has not sponsored an expert witness to endorse a CAPM approach, and nowhere in the Company's case is there any use of the CAPM or its risk measure (the "beta" coefficient) to estimate ROE. The Attorney General's efforts to offer new, unsubstantiated, and unsupported data analysis into the record of this case should be rejected.

4. Summary of Dr. Hadaway's Conclusions on ROE

To arrive as FG&E's cost of equity estimate of 11.5%, Dr. Hadaway averaged the median results of his three DCF analyses. Id. at 28 (Gas) and 30 (Electric), Tr. 8/22/02 (Vol. 10) at 1129. These results were supported by his risk premium analysis, which produced a result of 11.9% for the Gas Division and 12% for the Electric Division. Id. A combination of DCF and risk premium methods is the most reliable approach to estimating ROE. The relatively wide range of results from the three DCF models used demonstrates that uncertainty and a level of transition currently exist, but the average of the three results is very close to the results of his conservative analysis of the equity risk premiums based on authorized regulatory rates of return. Based on the three DCF analyses, the risk premium analysis, and his review of current market, industry and Company-specific data, Dr. Hadaway concluded that an 11.5 percent ROE is a fair and reasonable estimate of the current cost of equity capital for both the Gas and Electric Divisions of FG&E. Exh. FGE-SCH-1 (Electric) at 005; Exh. FGE-SCH-1 (Gas) at 005.

C. No Reduction in ROE is Warranted

The Attorney General's assertion that the Department should set FG&E's ROE at the "lower end of the reasonable range" on grounds that FG&E has failed to act as a "responsible corporate citizen" since restructuring is inaccurate and unsupported by record evidence. AG Br. At 1-2. Furthermore, in the current corporate environment, this allegation of material accounting errors is irresponsible. The record in this case demonstrates that FG&E has complied with all of the Department's recent directives in regard to establishing its base rates, including the timely filing of PBR plans for both its gas and Electric Divisions. Moreover, FG&E has provided its customers with stable base rates during the past 18 years during a time in which most utilities sought multiple base rate increases.

The Attorney General's list of recent "accounting errors" by the Company, in fact, represents disagreements over the Company's booking of charges that extend back over two decades in regard to the Seabrook Surcharge and gas inventory finance charges. One side effect of the Company avoiding base rate increases for its customers is that potential disagreements over the Company's practices maybe postponed for many years.

The Attorney General's overall mismanagement theory is inappropriate and should be rejected. In utility ratemaking matters and in the course of complex regulatory proceedings before the Department, there are frequently opposing view points and differences of opinion relating to accounting treatment an that may result in lengthy litigated cases. FG&E should not now be penalized with a reduced ROE because it defended legitimate positions in D.T.E. 97-115 and D.T.E. 99-66. The fact that the outcome of D.T.E. 99-66 and 97-115 were adverse to FG&E does not warrant a reduction in its ROE. Reducing FG&E's ROE for the reasons proffered by the Attorney General would have a chilling effect on FG&E rights to present a defense in cases before the Department and would send the wrong message to other utilities.

Under Department precedent, a company's ROE may be reduced when it has been demonstrated that the utility's performance has been deficient in certain areas. See Cambridge Elec. Light Co., D.P.U. 92-250 at 161-162 (1993); Boston Edison Co., D.P.U. 85-261-A 266-A at 14 (1986). These cases are inapposite, however, because there is no evidence that FG&E performance or service has been in any way deficient. To the contrary, in recent years, FG&E has consistently pursued and implemented investments to improve the reliability of its systems. In Service Quality of FG&E, D.T.E. 01-67 (2002), the Department found that FG&E had experienced limited outages during the Summer of 2001 and was able to restore power within a few hours, thus demonstrating the Company was adequately staffed and trained to handle emergencies. Id. at 10, 12. Furthermore, since restructuring, FG&E has exhausted its opportunities to mitigate its stranded costs, and it has the lowest default service rates in the Commonwealth. FG&E has also requested fewer base rate increases than any other Massachusetts utility, and is in compliance with the Department's policies concerning PBR initiatives.

Overall, FG&E has demonstrated that it is a good corporate citizen, and the Department should reject the Attorney General's efforts to chill FG&E's rights by arguing for a reduction in the Company's ROE based upon positions taken in cases litigated before the Department.

VIII. COST OF CAPITAL FOR THE GAS AND ELECTRIC DIVISIONS

A. Cost of Capital Return of Rate Base (Common) and Long Term Debt

The weighted cost of capital proposed by FG&E is 9.09 percent for the Electric Division and 9.09 percent for the Gas Division. Exh. FGE-MHC-1 at 075 (Electric); Exh. FGE-MHC-1 at 073 (Gas). FG&E's calculation begins with the test-year end balances of capital components, and is then adjusted by the long-term debt amount for the sinking fund payment of $3 million during early 2002. Exh. MHC-1 at 072 (Gas); Exh. MHC-1 at 071 (Electric). The cost of long-term debt was appropriately updated to reflect the sinking fund payment. The calculation was based upon the applicable cost rates for FG&E's preferred stock and long-term debt. Id. The embedded effective cost of capital for preferred stock and long-term debt was calculated at 6.81% and 7.55% respectively. Id.; see also Exh. FGE-MHC-1 at Sch. MHC-12 (Gas); Exh. FGE-MHC-1 at Sch. MHC-12 (Electric). In addition, during the proceeding, FG&E updated the common equity to reflect retained earnings and a correction to the principal amount of the 8.55%

long-term debt note. DTE-RR-6 updated 10/02/02 at Sch. ADJ (Electric), lines 13, 14 and Sch. ADJ (Gas) lines 14, 15. The cost of common equity for both the Gas and Electric Divisions calculated by Dr. Hadaway is 11.5%. Id. The updated weighted cost of capital for the Gas and Electric Divisions is 9.11%, consisting of 40.8% common equity, 2.4% preferred stock equity and 56.7% long-term debt. Id. Accordingly, FG&E has applied this rate to the total rate base of the Electric Division, for a return of $4,193,536 and to the total rate/base of the Gas Division, for a return of $2,707,352. DTE-RR-6, updated 10/02/02 at Sch. MHC-2 (Electric) and Sch. MHC-2 (Gas).

B. Response to Attorney General

Consistent with Department precedent, FG&E excluded short-term debt from its cost of capital calculation. Short-term debt is excluded because it is temporary financing which is generally replaced by long-term debt when a project is completed. According to the Attorney General, short-term debt should have been included in the calculation. AG Br. at 46-47. However, the Department has consistently rejected this argument. See, e.g. New England Tel. & Tel. Co., D.P.U. 86-33-G at 380-81 (1987). More recently, the Department reaffirmed its policy of excluding short-term debt from the capital structure, agreeing with the utility that short-term debt balances are too volatile and do not accurately represent a company's long-term capital costs. Massachusetts Elec. Co., D.P.U. 95-40 (1995). The fact that interest rates are currently low should not impact the Department's decision on this issue The Attorney General has failed to provide any new evidence or a convincing argument to depart from the Department's precedent for excluding short term debt from FG&E's capitalization. Accordingly, his proposal should be rejected.

IX. DEPRECIATION FOR GAS AND ELECTRIC DIVISIONS

A. Introduction

FG&E has presented a thorough, detailed, and well-documented depreciation study in this proceeding establishing that the appropriate composite annual electric plant accrual rate is 4.73%, the gas plant accrual rate is 4.61%, and the accrual rate for common plant is 6.19%. The new accrual rates result in an increase of $1,127,905 in the electric plant depreciation expense and $109,199 in the gas plant depreciation expense, based on plant investment as of December 31, 2001. DTE-RR-6, updated 10/02/02 at Sch. MHC-7-20 (Gas); Sch. MHC-7-17 (Electric). The increase in the depreciation rates over the existing depreciation accrual rates of 3.06% (Electric), 4.06% (Gas) and 4.10% (composite) is primarily due to changes in net salvage estimates, although the electric plant increase is somewhat offset by higher average life estimates. Exh. FGE-JHA-1 (Electric) at 067.

The Attorney General has failed to demonstrate any significant flaws in FG&E's depreciation study. AG Br. at 39-44. Instead he has resorted to vague and imprecise criticisms of FG&E's witness' "judgment" which are not supported in the record and are unpersuasive. The Department should accept FG&E's study and adopt the recommended electric, gas and composite depreciation accrual rates.

B. FG&E's Depreciation Study

Mr. James H. Aikman, FG&E's depreciation expert, prepared the study. As Mr. Aikman stated in his prefiled direct testimony:

> [T]he purpose of depreciation study is to develop accrual rates reflective of engineering judgment, current industry and specific company experience and current projection for the future, for the particular depreciable assets under study. The objective of depreciation as an element of the cost of service is to provide for the appropriate recovery of the investments in depreciable assets

> over a life term that assures the full recovery of the investment less estimated net salvage.

FGE-JHA-1 at 069 (Electric) and 064 (Gas).

Mr. Aikman employed essentially the same approach as he has used in previous studies that have been accepted by the Department. See e.g., Berkshire Gas Co., D.T.E. 01-56 (2002); Berkshire Gas Co., D.P.U. 192-210 (1993); Eastern Edison Co., D.P.U. 1580 (1984); Commonwealth Gas Co., D.P.U. 87-122 (1987); Boston Gas Co., D.P.U. 88-67 (1988); Commonwealth Electric Co., D.P.U. 88-135/151 (1989); Commonwealth Electric Co., D.P.U. 90-331 (1991).

Mr. Aikman's experience and credentials as a well-qualified expert in the field of depreciation are well established. He has testified before the Department, as well as other state commissions, many times. Indeed, the Department has praised depreciation studies that Mr. Aikman has prepared for other Massachusetts utilities as thorough and well-documented. See, e.g., Boston Gas Co., D.P.U. 88-67, at 159. The Department has stated that Mr. Aikman is a "well-seasoned expert in the field of depreciation" and that he possesses "an appropriate understanding of the results generated by his computer program and possesses the engineering knowledge and experience appropriate to interpreting those results." Commonwealth Electric Co., D.P.U. 90-331, at 52.

1. Data Compilation

In the fourth quarter of 2001, Management Applications Consulting, Inc. (MAC) of Reading, Pennsylvania was authorized to conduct depreciation rate studies of FG&E's electric, gas, and common utility properties. Exh. FGE-JHA-1 at Sch.-JHA-1 at 087. In addition to reviewing and analyzing FG&E's data base and historical plant accounting records, on January 28, 2002, Mr. Aikman conducted a tour of FG&E's physical plant to familiarize himself with

FG&E's electric and gas property and operations. Exh. DTE 1-13; FGE-JHA-1 at Sch.-JHA-1 at 094. Mr. Aikman personally visited and inspected FG&E's above-ground property and consulted with various members of Company management to obtain a thorough understanding of FG&E's systems and equipment. See Exh. DTE 1-14. He solicited input from FG&E personnel about past practices and experience as well as future plans and expectations for impacts on mortality patterns, average service lives, cost of removal and salvage. Id. Such visual inspections and face-to-face meetings with management to supplement the statistical results are consistent with the Department's requirement to "go beyond the numbers presented in a depreciation study and consider the underlying physical assets at issue." Berkshire Gas Co., D.T.E. 01-56, at 92 (2002); Massachusetts Electric Co., D.P.U. 200, at 21 (1980); Lowell Gas Co., D.P.U. 19037, at 20 (1977).

2. Life Analysis

Mr. Aikman next analyzed the historical data in order to develop recommended remaining life accrual rates for each category of electric and gas plant. Exh. FGE-JHA-1 (Electric), at 070-072, Exh. FGE JHA-1 (Gas) at 76-78. Mr. Aikman employed the universally accepted Simulated Plant Record ("SPR") technique for the life analysis in his study. Exh. FGE-JHA-1 at 070 (Electric) and 065 (Gas). A detailed description of the SPR technique is contained in Mr. Aikman's direct testimony. Id. In summary, SPR is an iterative procedure in which certain values (survivor factors) from empirical survivor curves (Iowa curves) are applied to the actual, recorded annual additions to generate theoretical surviving year-end balances. Id. The analysis identifies the empirical curves that best simulate the actual ending balances in a specified band of years, e.g., 10, 20, or 30 years. Id.; see also Tr. 8/6/02 (Vol. 2) at 215-216.

The Attorney General erroneously asserts that FG&E fails to discuss or explain its significant electric depreciation increase other than by reliance upon its expert's judgment which the Attorney General repeatedly disparages, and refers to as "opinion shopping". AG Br. at 39, 41. The Department has repeatedly cautioned, however, that a depreciation study must not rely solely on statistical analysis but should also rely upon "the judgment and expertise of the preparer." Berkshire Gas Co., D.T.E. 01-56, at 92 (2002), See also D.T.E. 99-118, at 50 (2000); D.T.E. 98-51, at 77-78 (1999). Consistent with the Department's approach, Mr. Aikman uses SPR as an essential starting point in the life estimation process by providing a clue as to what happened in the past. SPR is not in and of itself life estimation. Exh. FGE-JHA-1 at 071 (Electric) and 066 (Gas). It is Mr. Aikman's task, as the depreciation expert, to use his judgment to predict what will occur in the future. Id.

In addition to the SPR statistical analyses, therefore, Mr. Aikman conducted an engineering evaluation, employing his expert judgment and almost 35 years of experience and relying upon the information he obtained in the course of his meetings with Company personnel. As Mr. Aikman testified, he:

> [A]nalyzed the historical data and . . . evaluated the output by considering the indications from those life analyses, input from the Company management, the character of the depreciable assets, knowledge gained during property inspections, my experience with like assets, and engineering knowledge and judgment.

Exh. FGE-JHA-1 at 070 (Electric) and 064 (Gas). It is therefore important to consider the nature of the particular assets in an account in determining whether the SPR life analysis is producing a realistic result. To this end, Mr. Aikman studied the pattern of annual additions to and annual retirements from the plant accounts to estimate the likely age of retirements, the approximate ages of the balance in the accounts, and to measure the volumes of additions and retirements in various time periods. Id.

As Mr. Aikman explained, judgment is particularly essential to adjust certain results of statistical analysis which common sense demonstrates are unrealistic or in some cases even preposterous. Tr. 8/6/02 (Vol. 2) at 263. For example, in the case of Account 361 -- Distribution Plant Structures and Improvements, Mr. Aikman declined to apply the results of the balance analysis that revealed a mean value of best fitting lives ranging from a low of 123 years to a high of 129 years. Id. In that instance, because the statistical results were completely unreliable, Mr. Aikman relied primarily upon his expert judgment and recommended an average service life of 35 years.

The Attorney General's assertion that FG&E does not attempt to explain or discuss its proposed electric depreciation expense increase is plainly incorrect. For each account, Mr. Aikman provides a description of the average service life produced by the statistical analysis, as well as an explanation of how, and why, he has adjusted or changed certain results, sometimes by recommending a longer proposed life, and sometimes a shorter proposed life. Exh. Sch.-JHA at 094-102.

As the Attorney General freely acknowledges, Mr. Aikman's study produces results that are conservative by avoiding drastic swings in indicated service lives that may be premature. The Attorney General stated:

> Mr. Aikman has had a long-standing rule that he would not immediately change from the existing estimated useful life for any plant account to the actuarial life that results from his statistical analysis, even if the statistics have recurred in study after study [citation omitted]. His preferred method, and the one often approved by this Department, is to make small, incremental movements towards the actuarial results that represent ten to twenty percent of the difference.

AG Br. at 42.[38]

For example, in Account 365 -- Overhead Conductors and Devices, Mr. Aikman has proposed a 40-year average service life in his study, a relatively minor change from the 35-year

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[38] The Attorney General complains that Mr. Aikman does not employ the same conservatism in his net salvage estimates. See infra § IX.B.3.C.

average service life implicit in the current authorized accrual rate, despite the fact that the statistical analysis indicated that the best fit would be a 50-year average service life. Mr. Aikman declined to move from 35 years to 50 years in "one fell swoop," judging that a gradual movement in increments is preferable to guard against wildly disparate results from one depreciation study to the next. Tr. 8/6/02 (Vol. 2) at 206-07. Moreover, the Attorney General has mischaracterized Mr. Aikman's gradual approach as an absolute rule of 10%-20%. As Mr. Aikman testified, he uses his expert judgment and, depending upon the circumstances, adjusts the estimate by something in the range of 10-20%. Tr. 8/6/02 (Vol. 2) at 207. Mr. Aikman's conservatism also works in both directions, in that for Account 362 -- Station Equipment he recommends a 46-year average service life, a significantly longer life than the 35-year ASL that resulted from FG&E's 1984 depreciation study. The longer average service life has the effect of significantly reducing the depreciation expense. Tr. 8/6/02 (Vol. 2) at 220-21.

3. <u>Net Salvage Analysis</u>

Mr. Aikman also determined net salvage estimates for FG&E's depreciable electric and gas plant and incorporated these values into the annual depreciation accrual rates. Exh. FG&E-JHA-1 (Electric) at 078; Exh. FGE-JHA-1 (Gas) at 073. The electric plant depreciation rates he recommends result in considerably higher depreciation expense than derived using the existing depreciation accrual rate primarily due to changes in the net salvage estimates. <u>Id.</u> The lower net salvage estimates than those implicit in the existing electric depreciation accrual rates are due to changes in environmental concerns and disposal requirements since prior depreciation studies (<u>i.e.</u>, 1984). It should also be noted that four years ago, FG&E's depreciation expert in D.T.E. 98-51 also proposed net salvage estimates not significantly different from Mr. Aikman's. <u>See</u> Exh. FGE - DGD-1-22. The evidence, therefore, that net salvage estimates are decreasing due to escalating disposal costs cannot be denied. For example, as Mr. Aikman explained:

> I now pay a fee to dispose of automobile tires and batteries that I didn't pay 20 years ago, and I pay $25 to $40 for the disposal of each mattress, stove, refrigerator, etc.

Id. Oil-filled equipment such as line transformers cost electric utilities money for disposal, contrary to 20 years ago when utilities could actually realize gross salvage by selling retired transformers for scrap. Id. at 078-079.

Without citation to the record, the Attorney General asserts that Mr. Aikman fails to employ the same "conservatism" to his net electric plant salvage estimates that he employs in adjusting the average service lives for each account. See AG Br. at 42-43. The Attorney General has produced an elaborate chart in which he purports to adjust Mr. Aikman's electric net salvage estimates to reflect an "incremental" movement to the actual net salvage estimates.

The Attorney General's example is based upon the erroneous assumption that Mr. Aikman bases the life adjustment of typically 10 to 20% on the difference between the current estimate and the proposed estimate. In fact, Mr. Aikman adjusts the existing estimate by approximately 10-20 percent. Furthermore, the Attorney General confuses apples and oranges and misapprehends the distinction between the process for estimating average lives and the reason behind the net salvage estimates. Mr. Aikman explained that the reason for the significant decrease in the net salvage estimates since the prior study is the dramatic increases in disposal costs for utilities compared to 20 years ago. Exh.FGE-JHA-1 at 078-79 (Electric). Unlike the wild fluctuations that occur in average service life estimates that may be attributable to some esoteric statistical phenomenon, the rising costs of disposal for utilities are demonstrable and quantifiable. As it is also highly unlikely that these disposal costs will decrease dramatically before the next study, no incremental movement is necessary. To the contrary, as environmental concerns escalate, resulting in more federal, state and local legislation governing waste disposal and land use, disposal costs will probably continue to rise. Therefore, it is appropriate to reflect the full impact of the increased costs in the proposed net salvage estimates and the Department should reject the Attorney General's "incremental" estimates.

4. Study of Gas Mains by Material Type

The Attorney General requests that the Department deny FG&E's entire gas depreciation increase of $210,000 because "Mr. Aikman failed to follow the directives of the Department to perform a gas main actuarial study by material type." AG Br. at 40. The Department's order to Berkshire Gas to perform its next mains and services actuarial analysis by material type was issued on January 31, 2002 -- months after Mr. Aikman had commenced his FG&E study. See Berkshire Gas Company, D.T.E. 01-56 at 95 (2002). In fact, by February 2002, Mr. Aikman's study for FG&E was virtually completed. Tr. 8/6/02 (Vol. 2) at 282-83.

Contrary to the Attorney General's characterization, the Department's Order was specific to Berkshire Gas Company -- it was not a directive to all gas utilities to perform future gas main and services actuarial studies by material type. However, FG&E has noted the Department's preference in this regard and, going forward, will conduct the study by material type in its next rate proceeding.

X. ISSUES OUTSIDE THE RATE PROCEEDING

A. FG&E's Electric Division Default Service Solicitation

The Attorney General's assertions that FG&E has violated the Department's affiliate transaction rules, and should be assessed civil penalties based upon its procurement of default service through the Enermetrix Exchange are beyond the scope of this proceeding, unsupported by the record, and erroneous as a matter of law. Attorney General Brief at 78-79. FG&E welcomes a full examination, in the appropriate forum, of its use of the Enermetrix Exchange to provide its customers with the lowest default service rates in the Commonwealth. This matter, however, is beyond the scope of this base rate proceeding, in which there is little record evidence to assess the Attorney General's post-hearing assertions. To the extent the Department is compelled to address this issue in this case, FG&E requests that it take notice of filings by the Company and the Attorney General in other proceedings which reveal the flaws in the Attorney General's presentation.

The Attorney General makes no offer of proof as to the relevancy of this matter to these base rate proceedings.[39] The Department's docket in DTE 99-60 reveals that on October 3, 2001, and again on April 9, 2002, FG&E filed with the Department the results of its RFPs for default service, and revised tariffs. See D.T.E. 99-60, FG&E Default Service Tariff Filing (April 9, 2002 and October 3, 2001). In those filings, the Company discussed how "FG&E complied with the Department's competitive bidding requirements by posting its Default Service RFP on the web-based Enermetrix Exchange". Id. at 1. The Department reviewed FG&E's RFP using the Enermetrix Exchange and approved the resulting rates which were the lowest, or among the lowest, of any electric distribution company at the time. The Attorney General was an active party to the proceeding and filed no objections.[40]

Any issues regarding the procurement of default service are beyond the scope of this base rate proceeding. The Department's records in DTE 99-60 reveal no evidence of market abuse

[39] Rather, the Attorney General seeks to introduce this matter based on a suggestion of newly disclosed information: "During the course of these proceedings, information became available indicating that the Company's most recent default service procurement had been made through an internet exchange platform rather than through a traditional RFP process." AG Brief at 78. While the Attorney General implies that FG&E had failed to disclose its use of the Enermetrix, the Department's record in D.T.E. 99-60 and D.T.E. 01-54 demonstrate that the Attorney General has long been aware of FG&E's use of Enermetrix to solicit default service offers and Unitil's financial interest in Enermetrix.

[40] The record in DTE 99-60 also reveals that the Attorney General not only was served with copies of the Company's default service filings, but entered into a Non-Disclosure Agreement in order to obtain the confidential portions of the filing, including the description of the RFP process on the Enermetrix Exchange. The Department's records also belie the Attorney General's suggestion that Unitil's investment in Enermetrix was only revealed in this proceeding. On June 14, 2001, the Attorney General filed comments in DTE 01-54, on the Department's Competitive Market Initiative, noting Unitil's financial interest in Enermetrix. Moreover, discussions of Unitil's relationship with Enermetrix have figured prominently in financial reports routinely requested and reviewed by the Attorney General. See eg. Exh. AG-2(1), Att. 1, at 2 (Unitil 1999 Form 10-K); AG-1-2(3), Att. 2, at 7 (Unitil 2000 Annual Report to Shareholders).

and demonstrates that FG&E's solicitations using the Enermetrix Exchange have produced the most robust auctions for FG&E to date, and by far the lowest default prices in the Commonwealth. In contrast, prior to use of the Enermetrix Exchange, FG&E's default prices were among the highest in the Commonwealth. See DTE Web Site, Electric Restructuring in Massachusetts, Default Service, Prices for 2000 and 2001. After the first solicitation using Enermetrix, FG&E obtained the lowest fixed prices for default service among all Massachusetts utilities, across all rate classes, during the first six months of 2002. Id. After the second solicitation using Enermetrix, FG&E achieved the second lowest fixed default rates for the last half of 2002. Id.; see also Tr. at 1115 (noting Unitil's divestiture of Enermetrix).

FG&E sought and was granted approval by the Department for its default service procurement through the Enermetrix Exchange in a proceeding in which the Attorney General was an active participant. Contrary to the Attorney General's assertions, FG&E did not fail to seek any required approvals from the Department for an affiliate transaction because Enermetrix is neither an affiliate of FG&E's, nor of Unitil's, under the Department's Standards of Conduct or Chapter 164. See 220 CMR 12.02 et seq.; M.G.L. c. 164, §85. Enermetrix is not an affiliate of FG&E under 220 CMR 12.02 because it is not "owned or subject to the common control" of FG&E or Unitil. Nor did Unitil's investment in Enermetrix of less than 9% provide "sufficient control" to render Enermetrix an affiliate of Unitil or FG&E under M.G.L. c. 164, sec. 85. The Attorney General's assertion of affiliate abuse is unfounded and should be summarily dismissed.

B. DOER's Recommendation to Allocate Electric Costs to Generation Function

The DOER has recommended to the Department that costs that are not associated with distribution service be separated and billed to the generation or transmission function. DOER Br. At 5-7. However, FG&E's Electric Division rate filing is premised on the current precedent issued by the Department on the treatment of those costs. See DOER-RR-1, Att. at 1-3 (describing directives in D.T.E. 99-110 and FG&E's response). FG&E has complied with the Department's most recent directives with regard to the inclusion of certain costs in delivery service rates. Id. Therefore, for the purposes of this proceeding, FG&E continues to request that the Department include all the costs for which FG&E seeks recovery in cost of service. This is not to say that DOER is inappropriate in continuing to raise this issue: the Department's Default Service generic proceeding may be the more appropriate venue for full consideration of costs appropriately allocated to other suppliers and associated ratemaking treatment.

XI. CONCLUSION

Wherefore, for all the reasons set forth, Fitchburg Gas and Electric Light Company respectfully requests that the Department of Telecommunications and Energy grant its requests for rate relief pursuant to the evidence presented in this proceeding for its Electric Division and its Gas Division.

Respectfully submitted,

FITCHBURG GAS AND ELECTRIC
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